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Light Water Reactor Sustainability Program

Hydrogen Generation and Industrial Heat Opportunities for Nuclear Plants in the Gulf Coast

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EXECUTIVE SUMMARY

The United States (U.S.) nuclear-generation fleet stands as a critical national strategic asset, playing a pivotal role in achieving climate goals. Operating on light-water reactor (LWR) technologies, this fleet provides the largest share of U.S. carbon-free electrical generation, ensuring 24/7 clean-energy stability. With a proven track record of reliability while operating at high-capacity factors, consistently above 90%, the existing nuclear fleet serves as a cornerstone for sustainable energy.

The Department of Energy's (DOE's) Light Water Reactor Sustainability (LWRS), Flexible Plant Operations and Generation pathway addresses U.S. nuclear power plant (NPP) grid integration challenges in the face of evolving energy landscapes. Research at Idaho National Laboratory (INL) highlights the potential synergy between high-temperature steam-electrolysis (HTSE) technology and nuclear steam and electricity during periods of high renewable grid penetration.

Large-scale nuclear-integrated hydrogen production through HTSE presents significant potential for decarbonizing such energy-intensive sectors as oil refining, petrochemicals, ammonia, and fertilizers. The strategic advantage lies in the nuclear sector's capability to deliver clean electrical and/or steam output during periods of low demand. Nuclear-produced hydrogen—with its ability to provide high-purity clean H_2 well below the national standard of 1 kg of CO_2 per kg of H_2—represents a breakthrough methodology. This emphasizes the crucial role NPPs can fill in addressing the increasing need for clean hydrogen, establishing them as essential contributors to decarbonization.

This report specifically delves into hydrogen-generation opportunities from the U.S. Gulf Coast region. This study aims to assess NPP capabilities for hydrogen production and to identify practical nearby industrial and pipeline-operator off-takers for nuclear-integrated hydrogen production as well as to present some specific case-study analysis showing the conditions under which nuclear hydrogen production and sale can be profitable. Also considered in this report is preliminary analysis of nuclear-heat opportunities accessible near Waterford NPP via transportation of hypothetical steam pipelines and heat-exchange equipment.

Key aspects of this assessment include analyzing the baseline hydrogen-production capacity of 351 tonne/day per NPP unit for HTSE and 231 tonne/day for low-temperature electrolysis (LTE), identifying potential industrial customers in close proximity to the plants that could benefit from clean hydrogen or steam supply, and exploring tax-credit opportunities from such sources as Inflation Reduction Act (IRA), Section 45U and 45V. In particular, the production tax credits (PTCs) of 45U provide a power-production credit up to \$15/MWh for zero-emission nuclear-power production from existing nuclear reactors if the electricity price is less than \$25/MWh. The 45U tax credits will reduce gradually to zero once the electricity price is more than \$43.75/MWh. Also, the Section 45V PTC incentivizes clean hydrogen production with associated greenhouse-gas emissions of less than 4.0 kg of CO_2 per kg of hydrogen. This incentive provides a maximum tax credit of \$3 per kg of clean-produced hydrogen. Additionally, particular attention will be given to assessing the feasibility of providing steam to industrial users in the vicinity of the NPPs, further enhancing the market potential for nuclear-generated products. Through this analysis, the study aims to provide insight into the viability and market opportunities for leveraging NPPs in the clean-energy sector.

The selection of light-water reactors (LWRs) in the Gulf Coast for hydrogen integration is driven by strategic criteria, primarily the high capacities of reactors such as Comanche Peak and the South Texas Project, each generating over 2,400 MW. These capacities enable large-scale hydrogen production through electrolysis, crucial for meeting the industrial demands of the Gulf Coast. Based on current facilities (Tier 1), industries that could use blends of hydrogen (Tier 2), and potential demand, the region has significant hydrogen needs, particularly in industrial hubs like Waterford, River Bend, Grand Gulf, and South Texas, as Figure ES-1 shows. This makes these reactors ideal for hydrogen initiatives. The strategic locations of these reactors near major industrial centers ensure efficient hydrogen delivery, reducing transportation costs and supporting decarbonization efforts.

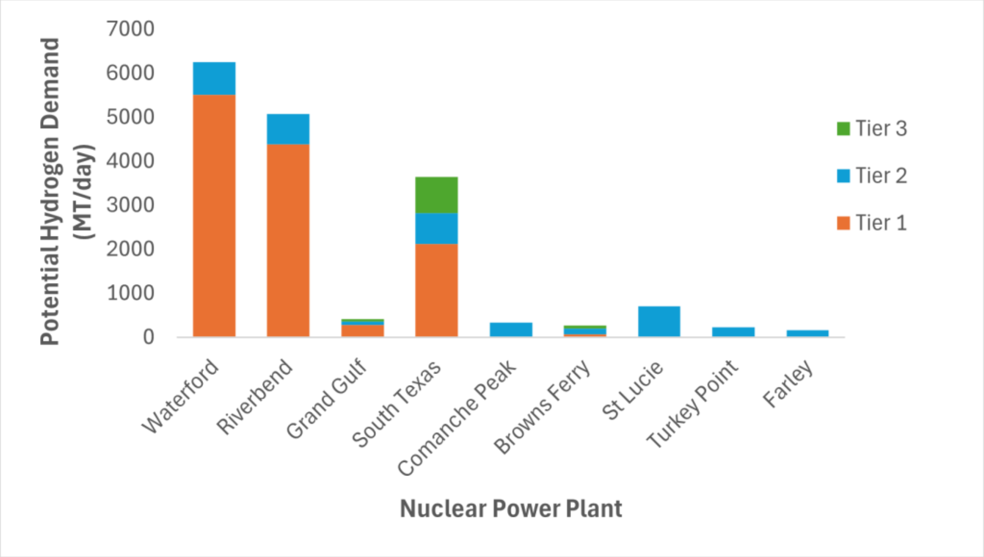

Figure ES-1. Potential demand of hydrogen around NPPs in the Gulf Coast according to different tiers.The Gulf Coast's extensive hydrogen-pipeline infrastructure further supports the integration of LWRs with hydrogen production. This comprehensive network facilitates efficient hydrogen transport from production sites to end users, minimizing the need for additional infrastructure investments. For example, Waterford and South Texas are in close proximity to existing pipelines, allowing hydrogen to be transported through the vast pipeline around the Gulf Coast, accelerating the deployment of nuclear-powered hydrogen production. Additionally, the region has potential hydrogen-storage capabilities, including as a compressed gas and in underground storage in salt caverns, to balance supply and demand, ensuring a continuous and reliable hydrogen supply. These factors make the Gulf Coast an optimal location for integrating high-capacity LWRs with hydrogen infrastructure. This study aims to assess hydrogen and steam opportunities for Waterford, River Bend, Grand Gulf, South Texas, and Comanche Peak NPPs based on these criteria.

Market Analysis

The market analysis anticipates substantial existing and potential hydrogen demand from different sectors, 6498, 5511, 412, 4356 and 442 MT/day for Waterford, Riverbend, Grand Gulf, South Texas and Comanche Peak NPPs, respectively. Based on Figure ES-2:

- Waterford 3 and Riverbend Station (RBS) and South Texas (STP) have the highest hydrogen demand surrounding them
- Ammonia and refineries appear as the predominant consumer of hydrogen, highlighting its role in supporting industries crucial for various economies
- Direct-reduced iron (DRI) exhibits the smallest demand, emphasizing the diverse landscape of hydrogen applications and the need for tailored strategies to meet specific regional and industrial requirements

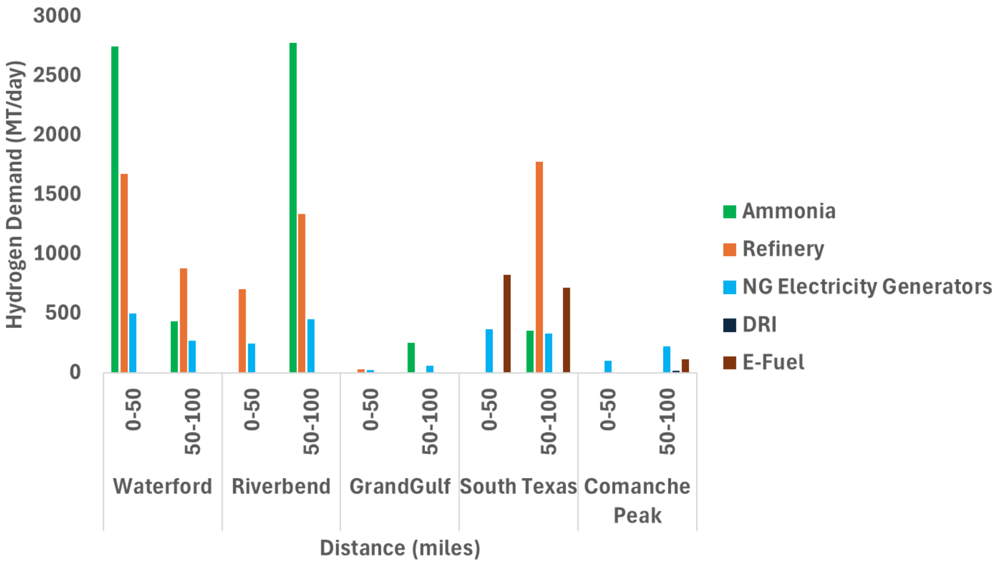

Figure ES-2. Future demand of hydrogen around case study plants.

Nuclear Integrated Hydrogen Production Analysis

The techno-economic assessment (TEA) conducted for Entergy's nuclear fleet evaluated the feasibility of integrating a 500 MW nominal HTSE facility and LTE. A custom Excel-based program, the Nuclear-Integrated Hydrogen Production Analysis (NIHPA) tool, was used to calculate the profitability. This study evaluates various scenarios of nuclear-integrated hydrogen production and their delivery mechanisms, categorized into four distinct cases described in Table ES-1:

Table ES-1. Case definitions used in this report.

Nuclear Integrated hydrogen production cases	Deliver Hydrogen to nearby hydrogen-pipeline network	Deliver Hydrogen to nearby industrial users
HTSE (Produce maximum 351 tons/day of H_2)	Case 1A	Case 1B
LTE (Produce maximum 231 tons/day of H_2)	Case 2A	Case 2B

For Cases 1A and 2A, hydrogen will be delivered to the nearest pipeline based on the National Pipeline Mapping System. For Cases 1B and 2B, hydrogen will be transported to the nearest potential demand site, such as ammonia, refinery, methanol and E-fuel. Detailed information is presented in Table 9 located in Section 5.

This TEA documents these cases based the market demand and the maximum hydrogen-supply capacity at a 100% capacity factor. Electrolyzer sizes are calculated according to the hydrogen-production rate, and if market demand exceeds the supply capacity, only a portion of the demand will be met based on the current electric and steam-diversion design. This design allows implementation without requiring a Nuclear Regulatory Commission (NRC) license-amendment request, although future front-end engineering and design studies may enable larger capacities. These evaluations provide a strategic foundation for integrating nuclear power with hydrogen production to meet market demands efficiently and safely.

The key assumptions are specified in Table ES-2.

Table ES-2. Lists of the assumptions for the critical parameters in TEA applied for all the selected plants.

Parameters used for TEA	Values	Assumptions
Start-up year of the hydrogen production	2030	It is assumed that the timing of study analysis window for hydrogen adoption is within 5 years.
Electrolyzer plant lifespan	20 years	Specific lifetime specified consistent with INL previous studies
Hydrogen market type	Regulated	NPPs are simplistically evaluated as merchant entities to avoid the complexities of a regulated utility framework.
Maximum electrolyzer capacity	500 MW-dc	Integration of steam extraction and electrical take-off modifications will be appropriately licensed under NRC rules without a license amendment to a maximum 500 MW-direct current of the electricity from NPP
Tax Credits: IRA 45V	\$3/kg-H2	hydrogen tax credit of \$3/kg-H2 for 10 years (2030–2039)
Tax Credits: IRA 45U	Gross receipt dependent	Nuclear clean-electricity tax credits from January of 2030 to December of 2032
Total installed direct capital cost (DCC)	\$397 million (in 2021 dollars)	The contingency is included for all sizes of the HTSE plants[a]
Additional integration costs including mechanical interface and switchyard for HTSE[b]	\$64 million	The total DCC is calculated by adding the installed DCC and the additional integration costs for HTSE
Additional integration costs including mechanical interface and switchyard for LTE [9]	\$32 million	The total DCC is calculated by adding the installed DCC and the additional integration costs for LTE
NPP capacity factor	93%	The averaged factors for all the plant in US.
NPP thermal efficiency	34%	The averaged factors for all the plant in US.

Three location-dependent parameters including the electricity price, state taxes and weighted average cost of capital (WACC) are considered from the selected plants as shown in Table ES-3.

Table ES-3. location-dependent parameters in TEA.

Parameter	Waterford	Riverbend	Grand Gulf	South Texas	Comanche Peak
Electricity price	\$35/MWh	\$35/MWh	\$35/MWh	\$31/MWh	\$20/MWh
State Tax	9.45%	9.45%	9.45%	6.25%	8.25%
WACC	5.66%	5.66%	5.66%	5.73%	5.69%

Table ES-4 compares the levelized cost of hydrogen (LCOH) with and without hydrogen-delivery costs (COD) and the change in net present value (NPV) of cashflows that compare NPV of cashflow in hydrogen production (NPV_{H2}) case with the NPV of cashflows in the business as usual (NPV_{BAU}) case.

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[a] Jacob Prosser et al. (2024). Cost Analysis of Alternative Large-Scale High-Temperature Solid Oxide Electrolysis Hydrogen Production Facilities. International Journal of Hydrogen Energy 49, pp. 207–227 http://dx.doi.org/10.2139/ssrn.4898266

[b] Tyler Westover, et al. (April 18, 2023). Preconceptual Designs of Coupled Power Delivery between a 4-Loop PWR and 100-500 MWe HTSE Plants. INL/RPT-23-71939, Rev 1. https://www.osti.gov/biblio/2203699

Table ES-4. Financial performance for NPP producing hydrogen before and after tax credits. The highlighted column shows the most profitable case among the selected plants.

	Nuclear Plants	Waterford		Riverbend		Grand Gulf		South Texas		Comanche Peak	
		Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax	Before Tax	After Tax
LCOH (\$/kg-H$_2$)	Case 1A	\$2.08	\$0.25	\$2.08	\$0.25	\$2.08	\$0.28	\$1.92	\$0.09	\$1.49	-\$0.27
	Case 1B	\$2.08	\$0.25	\$2.08	\$0.25	\$3.00	\$1.25	\$1.92	\$0.08	\$1.67	-\$0.11
	Case 2A	\$3.18	\$1.41	\$3.18	\$1.41	\$3.18	\$1.44	\$2.95	\$1.16	\$2.31	\$0.63
	Case 2B	\$3.18	\$1.41	\$3.18	\$1.41	\$3.90	\$2.21	\$2.95	\$1.16	\$2.47	\$0.75
LCOH+COD (\$/kg-H$_2$)	Case 1A	\$2.17	\$0.34	\$2.18	\$0.35	\$2.27	\$0.47	\$2.02	\$0.19	\$1.86	\$0.10
	Case 1B	\$2.18	\$0.35	\$2.18	\$0.35	\$3.24	\$1.49	\$2.01	\$0.17	\$1.96	\$0.18
	Case 2A	\$3.29	\$1.50	\$3.29	\$1.52	\$3.40	\$1.66	\$3.06	\$1.27	\$2.79	\$1.11
	Case 2B	\$3.29	\$1.51	\$3.29	\$1.52	\$4.14	\$2.45	\$3.04	\$1.25	\$2.76	\$1.04
ΔNPV (\$M) = NPVH$_2$-NPV$_{BAU}$	Case 1A	-\$1687	\$1219	-\$1674	\$1228	-\$1552	\$1316	-\$1459	\$1306	-\$532	\$1950
	Case 1B	-\$1674	\$1228	-\$1674	\$1228	-\$119	\$105	-\$1472	\$1296	-\$201	\$583
	Case 2A	-\$1769	\$292	-\$1769	\$305	-\$1651	\$378	-\$1531	\$389	-\$619	\$1019
	Case 2B	-\$1760	\$299	-\$1760	\$305	-\$199	\$43	-\$1549	\$376	-\$377	\$421

The NPV_{H2} in Table ES-4 is calculated based the hydrogen market price equivalent to the summation of LCOH and COD. This comparison is made for the four case studies of Waterford 3, Riverbend, Grand Gulf, South Texas Project, and Comanche Peak before and after taxes. The calculated LCOH represents the breakeven costs for each case, resulting in a zero NPV. The taxes considered include state and federal income taxes as well as potential tax credits from the IRA 45V.

Key Results in Table ES-4 suggest that, from LCOH without delivered cost included,

- LCOHs before and after taxes for Case 1A and 1B are lower than those for Case 2A and 2B for all plants because HTSE has a higher hydrogen-production rate than LTE with the same energy demand, yielding higher economic benefits.
- Case 1A and 1B have the same LCOHs for Waterford, Riverbend, and South Texas NPP as these plants produce the maximum hydrogen to meet demand. Similarly, Case 2A and 2B have identical LCOHs before transportation costs are included.
- LCOHs for Case 1B and Case 2B are slightly higher for Grand Gulf and Comanche Peak due to reduced hydrogen demand and corresponding electrolyzer sizes due to larger electrolyzer sizes resulting in lower LCOHs, suggesting the benefit of a pipeline network serving multiple industrial users.
- After-tax cases with tax credits reduce LCOH by about \$1.8/kg-H_2.

LCOHs for Case 1A and Case 1B, including tax credits, result in a negative cost of hydrogen for Comanche Peak. In a deregulated market, the utility may reduce the market price for hydrogen due to the IRA tax credits, allowing it to compete with blue hydrogen.

From LCOH with delivered cost:

- Hydrogen delivery costs have an minor impact on overall LCOH and cost of delivery (COD).
- The highest CODs are less than \$0.5/kg-H_2 at Comanche Peak due to longer transportation distances and relatively low demand.
- Waterford and Riverbend have the lowest overall LCOH and COD due to high demand and shorter distances to pipelines and industrial users.

The delta NPV of cashflow is always negative before considering tax credits, indicating producing hydrogen is less profitable than selling electricity to the grid when electricity costs are the same for both purposes. However, if electricity costs are slightly lower than the selling price, some cases could have a positive delta NPV:

- After tax credits (IRA 45V) are applied, the delta NPV of cashflow for HTSE (Case 1A and 1B) is positive, making HTSE the preferred method for all the selected plants
- The higher use of electricity in LTE leads to higher NPV business as usual (BAU) of cashflows for Case 2A and 2B
- In the Gulf coast region, different hydrogen production scenarios are recommended based on the maximum delta NPV (highlighted in Table ES-4), indicating the most profitable scenarios. For Waterford, it is recommended to produce hydrogen onsite through HTSE and delivered to the nearby industrial users. For Riverbend, producing hydrogen onsite through HTSE and delivered to either nearby pipeline network or industrial users are equally profitable. For Grand Gulf, South Texas, and Comanche Peak, producing hydrogen onsite through HTSE and delivered to the nearby pipeline network in these locations are the most profitable scenarios.

The sensitivity studies demonstrate that the selected inputs for estimating the LCOH provide consistent rankings for both HTSE and LTE across different plants, with electricity price being the most-sensitive parameter, followed by plant electrolyzer capacity. Electricity price is crucial due to its role as the primary feed for hydrogen production, while plant electrolyzer capacity affects daily output and DCCs. Despite this, the impact of DCCs is minor compared to electricity price and plant capacity. For NPV of cashflows, electricity price and hydrogen market price are the most-sensitive parameters, with maximum NPV achieved when electricity prices are low and hydrogen market prices are high. Increasing electrolyzer-plant capacity can increase hydrogen production and revenue, but may result in a negative NPV of cashflows due to higher electricity-sales revenue, particularly in the maximum 500 MW-dc scenario.

On the other hand, the competitive analysis compared nuclear-integrated hydrogen production and blue hydrogen production, focusing on LCOH with and without PTCs and the LCOH of steam methane reforming (SMR) with and without carbon-capture sequestration (CCS) for Case 1B and 2B. The results, presented in Figure ES-3, include data for Waterford, Riverbend, and South Texas, which share the same capacity and exhibit limited variability for the WACC.

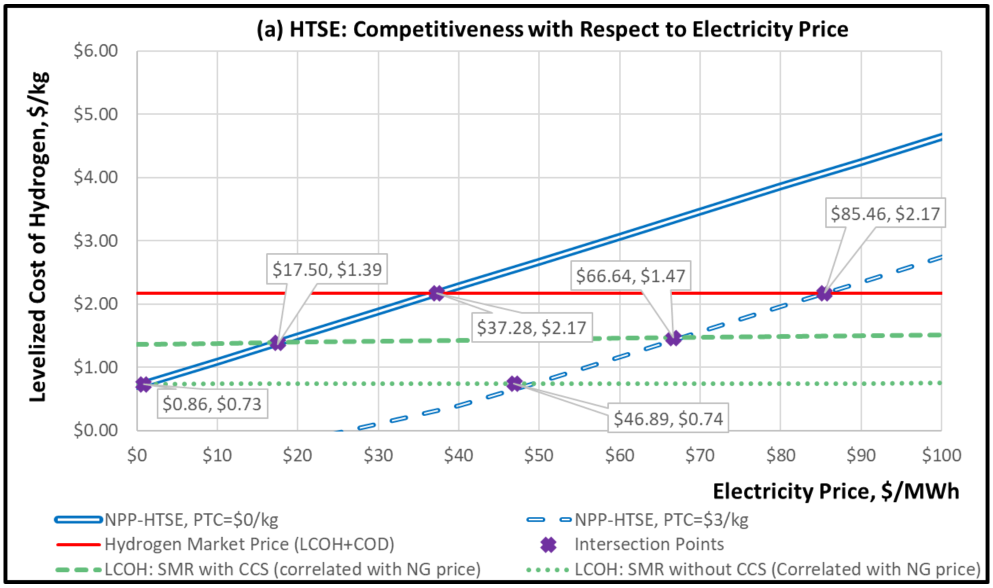
Key findings of this analysis are:

- *Competitiveness with PTCs*. Nuclear-integrated hydrogen production with PTCs is competitive with SMR, depending on the natural gas price for SMR and the electricity and hydrogen prices for HTSE
- *Electricity Price Dependency*. The LCOH for both nuclear-integrated and SMR hydrogen production is highly dependent on electricity price.

Additionally, the LCOHs of nuclear-integrated hydrogen production (blue hollow lines) and SMR (green dashed lines) are both influenced by electricity prices. However, the nuclear-integrated hydrogen production lines are steeper, indicating higher electricity consumption compared to SMR. The intersection points in Figure ES-3 highlight competitive electricity prices for various scenarios. For instance, nuclear-integrated hydrogen production:

- With PTC is competitive when electricity price is below \$67/MWh for HTSE. In this case, producing hydrogen by integrating 500 MW-dc HTSE with Waterford, Riverbend, and Grand Gulf NPPs is competitive with blue hydrogen because the electricity price ranges from \$25 to 40/MWh. For South Texas Project and Comanche Peak NPP, producing hydrogen is competitive with blue hydrogen when the electricity price ranges from \$17/MWh to \$67/MWh.
- With PTC competitive for LTE with PTC if the electricity price is below \$34 per MWh. In this case, producing hydrogen by integrating 500 MW-dc LTE with Waterford, Riverbend, and Grand Gulf NPP is only competitive to the blue hydrogen when the electricity price ranging from \$25/MWh to \$34/MWh. For South Texas Project and Commanche Peak NPP, producing hydrogen is competitive to the blue hydrogen considering that the electricity price ranges from \$17/MWh to \$34/MWh.
- Without PTC is competitive when the electricity price is below \$17/MWh for HTSE. In this case, producing hydrogen by integrating a 500 MW-dc HTSE with NPP is not competitive to blue hydrogen because the electricity price ranges from \$17/MWh to \$122/MWh.
- With PTC is competitive for LTE if the electricity price is below \$4/MWh. In this case, producing hydrogen by integrating 500 MW-dc LTE with NPP is not competitive to blue hydrogen because the electricity price ranges from \$17/MWh to \$122/MWh.

Grand Gulf and Comanche Peak, with smaller electrolyzer sizes due to lower hydrogen demand, are competitive when tax credits are considered.



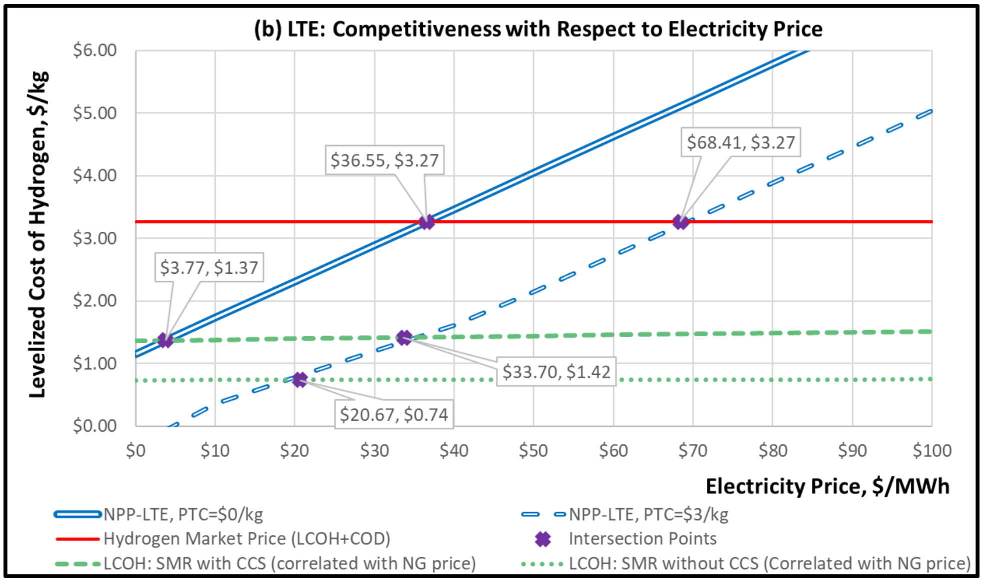


Figure ES-3. Competitive analysis with respect to electricity price for hydrogen production through (a) HTSE or (b) LTE with 500 MW-dc of electrolysis design capacity, 20 years of plant life, 5.7% of WACC, user-defined electricity fixed price, and hydrogen market price equivalent to summation of LCOH and COD.

Avoided Cost of CO_2

This study analyzed the avoided cost of carbon for all cases presented above with the purpose of assessing the economic viability and environmental benefits associated with different hydrogen-production methods. This evaluation focuses on the potential costs involved in mitigating CO_2 emissions, providing insight into the financial impact and effectiveness of employing tax credits and other incentives. Comparing avoided carbon costs across various plants and production scenarios allows a better understanding of how these factors influence overall carbon-mitigation strategies.

The findings reveal that the avoided cost of carbon ranges from $247.1 to 478.8/tonne of CO_2, with variations depending on the specific plant. Case 2 shows a higher potential cost for mitigating CO_2 emissions than the other cases. However, the implementation of tax credits has a substantial impact on reducing these costs, lowering the avoided net cost of carbon to a range between $29.7 and 275.6/tonne of CO_2. This significant reduction highlights the effectiveness of tax incentives in making carbon mitigation more economically feasible.

Thermal Energy Transport Cost Estimation

The capital cost estimate for the steam transport infrastructure was based on a preconceptual design and cost analysis from Sargent & Lundy, which was scaled to meet the requirements of this Gulf Coast study. The steam-delivery system was designed to meet an industrial-user requirement of 1 million lb/hr of 600 psi saturated steam, extracted from the main steam system before the high-pressure turbine to ensure minimal heat loss and maximum efficiency.

Key results were:

- Costs include piping and two reboilers, with each reboiler costing approximately $1 million
- Total estimated cost for steam-transport infrastructure is $12.5 million to transport 1 million lb/hr of 600 psi saturated steam 2 miles
- Comparative cost of heat delivery are
    - Nuclear steam extraction: $13.0/MWhth
    - Natural gas-fed boiler: $13.64/MWth
- At a natural gas price of $4.59/MMBTU, nuclear steam and natural gas boiler costs break-even.

The increasing environmental, social, and governance (ESG) pressures on industrial facilities enhance the attractiveness of always-available clean steam. Further investigation into the application of PTCs for clean steam is recommended to assess its impact on the financial feasibility of thermal-energy transport.

Risk Assessment

The safety of hydrogen production at NPPs involves addressing two primary hazards: fire and deflagration or detonation. An ignition source in the presence of a hydrogen leak can lead to a plume fire or a deflagration, with the latter potentially resulting in a more-severe detonation. Detonations are analyzed as the bounding overpressure event due to their higher risk. HyRAM+ software from Sandia National Laboratories was employed to visualize and calculate the regions susceptible to different hazards from a jet-leak detonation of hydrogen.

Safety and regulatory licensing considerations are influenced by the existing fire protection plans of each NPP, which are approved by the U.S. NRC. These plans, often based on National Fire Protection Association (NFPA) standards, dictate the safe standoff distances required to mitigate fire hazards and resultant heat flux. Detonation-overpressure safe distances are defined by the dissipation of the overpressure wave to 1.0 psi. NFPA 55 provides guidelines for standoff distances based on reasonable leak percentages while the NRC's Regulation Guide 1.91 employs a more-conservative approach using a TNT-equivalence calculation for explosive hazards. Recent research by Idaho National Laboratory (INL) on a 500 MW HTSE facility suggests that a conservative standoff distance of 233 m to the nearest safety-related structure, system, or component is sufficient. This distance fits within the owner-controlled area of typical NPPs and meets the fire-protection plan requirements. This conservative methodology is recommended to site hydrogen facilities although NFPA standards or a Bauwens-Dorofeev methodology may be considered for less conservative, yet acceptable, safe separation distances.

Summary and Future Work

This report focuses on hydrogen-generation opportunities in the U.S. Gulf Coast region, assessing NPP's capabilities to produce hydrogen and identifying potential industrial off-takers. The study evaluates various scenarios for nuclear-integrated hydrogen production, analyzing both technical and economic feasibility. Key findings include the significant potential for decarbonizing industries like oil refining and ammonia production through nuclear-generated hydrogen. The Gulf Coast's extensive hydrogen-pipeline infrastructure and storage capabilities further support this integration, highlighting the strategic advantage of locating high-capacity LWRs near major industrial centers with substantial demand, fostering growth and expanding market for advanced energy solution. Additionally, the report explores potential tax credits and incentives, such as those from the IRA, which could enhance the economic viability of nuclear-integrated hydrogen production.

Given the high hydrogen demand in the Gulf Coast area described in Figure ES-1, the current capacity of LWRs alone will not suffice. Future work aims to explore the synergy between LWRs and advanced reactors to adequately meet the region's hydrogen requirements. This involves evaluating the integration of these reactor types to enhance hydrogen-production capacity, leveraging the strengths of both technologies. In doing so, the study seeks to provide a more-robust and scalable solution to address the growing industrial demand for clean hydrogen in the Gulf Coast.

Additionally, the study proposes a detailed evaluation of time-dependent electricity-price data to optimize the decision-making process for selling electricity, producing hydrogen, or exporting steam. This could be done by implementing the Holistic Energy Resource Optimization Network (HERON), developed by INL, to find the optimized scenarios. Integrating results from the TEA and risk analysis, a decision-making algorithm will be developed to assist industry stakeholders in evaluating various scenarios involving risk and cost. Further analysis of unregulated markets in the Gulf Coast that consider price fluctuations will also be conducted to identify economically viable configurations. Integration of the Standard Economic Tool, NIHPA, and HERON will facilitate comping results for different scenarios, providing a comprehensive framework for optimizing the economic and operational performance of hydrogen-production and industrial-heat opportunities in the Gulf Coast region.

CONTENTS

FIGURES

TABLES

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ACRONYMS AND DEFINITIONS

Acronyms	Descriptions	Definitions
ARMA	Autoregressive moving average	
ASU	Air separation unit	Industrial unit operation is used to separate N2 from O2
BASF	Badische Anilin und Soda Fabrik	German chemical company
BAU	Business-as-usual	The operation mode that the plant only produces electricity and sale the electricity to the grid
BF	Blast furnace	Unit operation used in steel making
BIC	Bayesian information criteria	
BWR	Boiling-water reactor	A type of nuclear reactor where the core needs to be cooled by deionized water
BIL	Bipartisan Infrastructure Act	Recent congressional legislation
CCS	Carbon-capture sequestration	One technology to reduce the carbon emissions from the production process
CCU	Carbon capture and utilization	
CEPCI	Chemical Engineering Plant Cost Index	A tool used to adjust the plant construction costs from one period to another
CF	Central Farmers	
CHP	Combined heat and power	Systems producing both heat and electricity as products
CT	Combustion Turbines	Turbines used to produce power via combustion
DFMA	Design for Manufacturing and Assembly	An engineering methodology to expedite the manufacturing process by reducing the time to market and total production costs
DOE	Department of Energy	A government agency in the United States
DRI	Direct-reduced iron	New process being used in iron making
EAC	Energy-attribute certificates	Instruments used to track clean energy consumption
EAF	Electric arc furnace	Unit operation in iron making
EIA	Energy Information Administration	An organization that collects the feedstock price data, including electricity, natural gas in the U.S.
EPA	Environmental Protection Agency	
ESG	Environmental, social, and governance	Investing in a way of supporting companies based on their commitment to one or more ESG factors
FT	Fischer-Tropsch	Process to make synthetic fuels from syngas (CO and H2)
GHG	Greenhouse gas	Gases that trap heat in the atmosphere
GREET	Gases, Regulated Emissions, and Energy Use in Transportation	Life-cycle analysis (LCA) suite of models in 1994, with the first version released in 1995, LCA is a framework for assessing the environmental impacts associated with all stages of the supply chain of a technology or product

Acronyms	Descriptions	Definitions
HERON	Holistic Energy Resource Optimization Network	
HFTO	Hydrogen and Fuel Cell Technology Office	A department under DOE to guide the research activities related to hydrogen and fuel cells in the U.S.
HTEF	High-temperature electrolysis facility	
HTSE	High-temperature steam electrolysis	An electrolyzer that utilizes both heat and electricity to transform deionized water to produce hydrogen
HTE	High-temperature electrolysis	Same as HTSE
INL	Idaho National Laboratory	A governmental research facility owned by Battelle Energy Alliance, LLC
IRA	Inflation Reduction Act	The law passed by congress regarding the tax incentives to reduce the impacts of inflation
IRR	Internal Rate of Return	The annual rate of growth that an investment is expected to generate
IRS	Internal Revenue Service	Part of the U.S. Department of the Treasury that is responsible for enforcing and administering federal tax laws, processing tax returns, performing audits
ITC	Investment tax credit	A federal tax incentive for business investment included in Section 48 of the U.S. tax code generated by qualified projects in renewable energy
LCA	Life-cycle assessment	A methodology to assess environmental impacts associated with all the stages of the life-cycle of a commercial product, process, or service
COD	Levelized cost of (hydrogen) delivery	
LCOH	Levelized cost of hydrogen	The costs of hydrogen production through a lifetime of the hydrogen production facility
LSU	Louisiana State University	-
LTE	Low-temperature electrolysis	An electrolizer that utilizes only electricity to transform deionized water to produce hydrogen
LWR	Light-water reactor	A reactor that uses deionized water (H2O) as the coolant
LWRS	Light Water Reactor Sustainability	One of the programs in in INL to support the existing LWR in the U.S.
MLE	Maximum likelihood estimation	
MT	metric ton	A measuring unit of weight
NFPA	National Fire Protection Association	
NIHPA	Nuclear-Integrated Hydrogen Production Analysis	A tool developed at INL to perform techno-economic analysis for nuclear-integrated hydrogen productions

Acronyms	Descriptions	Definitions
NPMS	National Pipeline Mapping System	
NPP	Nuclear power plants	One type of the electricity and thermal power generators
NPS	Nominal pipe size	-
NPV	Net present value	The difference between the present value of cash inflows and the cash outflows over time
NPVBAU	Net present value for business-as-usual	The NPV of the BAU representing selling of electricity to the grid
NPVH2	Net present value for hydrogen production	-
NRC	Nuclear Regulatory Commission	-
O&M	Operations and maintenance	The costs associated with operating and maintenance
PTC	Production tax credit	A per kWh federal tax credit included under Section 45 of the U.S. tax code for electricity generated by qualified renewable energy resources
PWR	Pressurized water reactor	A type of nuclear reactor where the core needed to be cooled by the deionized water with steam generated through a steam generator
RAVEN	Risk Analysis Virtual Environment	
S&L	Sargent and Lundy	Engineering contractor
SMR	Steam methane reforming	One technology that is used to produce hydrogen using natural gas and electricity as the feedstock
TDL	Thermal energy delivery loop	Heat transfer equipment for extracting heat from the nuclear plant for use other than for power generation
TEA	Techno-economic assessment	The economic assessment for the new developing technologies
TJ	Terajoule	-
WACC	Weighted average cost of capital	The utility’s average after-tax costs of capital from all sources including stocks, debts, and other format of debts

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Hydrogen Generation and Industrial Heat Opportunities for Nuclear Plants in the Gulf Coast

1. INTRODUCTION

As the world seeks solutions to transition towards sustainable and low-carbon energy, hydrogen has gained attention as a potential versatile energy carrier and proven chemical feedstock with applications ranging from transportation and energy storage to industrial chemical and product synthesis. Recent growing recognition of the pivotal role that hydrogen can play in the transition towards a sustainable and low-carbon energy future has seen nuclear power plants (NPPs) emerge as key players in unlocking the vast potential of clean, near-zero-carbon hydrogen production and heat for industrial use. This study aims to explore the opportunities and synergies surrounding hydrogen production in the vicinity of Entergy's NPPs. Heat transport for industrial use is a possible strategy for additional future analysis.

The current U.S. light-water reactor (LWR) nuclear-generation fleet is increasingly recognized by governmental, scientific, public-policy, and industrial communities as having a strategic role in supporting the ongoing national transition to a clean-energy future. The Department of Energy (DOE) Light Water Reactor Sustainability (LWRS) Program Flexible Plant Operations and Generation Pathway develops options to assist U.S. NPPs in all these areas to enable NPPs designed for steady baseload operation to integrate with intermittent wind and solar capacity by flexibly dispatching heat and electricity to industrial users to assure reliable clean energy for the nation.

In recent years, the development of clean water-splitting electrolysis systems has dramatically accelerated as interest has increased in clean hydrogen production and the global decarbonization of industry. Electrolyzed hydrogen produced intermittently by renewables via low-temperature electrolysis (LTE) is already emerging as one such near-term clean-energy product. Dispatching electricity and heat to produce nuclear-integrated hydrogen for industrial use can reduce financial stress on NPP operators when intermittent renewables are producing peak generation, and the need for NPP baseload power is correspondingly reduced. This alternate-product stream for NPPs can provide clean hydrogen to hard to decarbonize sectors. Nuclear generators are unique in their capability to deliver both clean electrical- and heat-energy output at a high-capacity factor: the two components needed to produce clean hydrogen from high-efficiency high-temperature steam electrolysis (HTSE), shown in Figure . This creative use of NPP electrical and steam energy to produce clean hydrogen helps decarbonize hard-to-decarbonize sectors that are dependent on heat-based industrial processes that currently rely on natural gas.

HTSE systems can achieve higher overall system efficiencies, relative to LTE, by using steam extracted from an NPP. Steam drawn from the NPP leads to significant comparative efficiency gains by reducing efficiency losses associated with converting steam to electricity through the full Rankine steam cycle traditionally used in NPPs. The hydrogen can also be produced continuously, with high-capacity factors using nuclear energy as opposed to the intermittent production of hydrogen via LTE using solar and wind energy. This fact enables nuclear hydrogen produced via HTSE to be more efficient and continuously to serve heavy industrial users of hydrogen as a chemical feedstock for existing industrial processes on the path towards decarbonization.

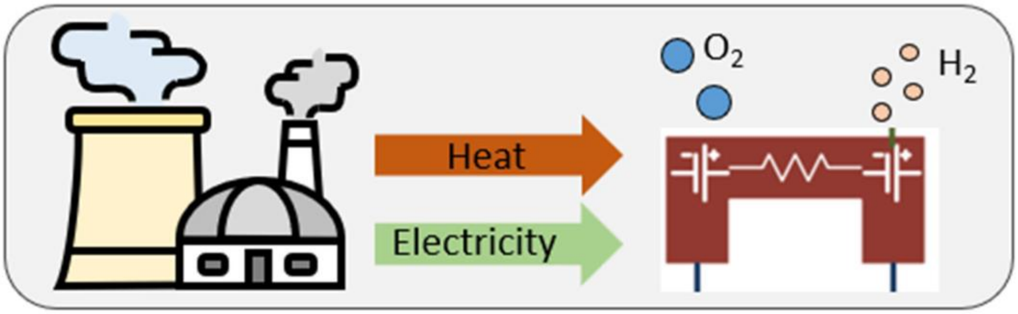


Figure 1. Integration of hydrogen production via HTSE by using nuclear plants.

Federal incentives and actions are aligning to expand the role of nuclear power as a viable and flexible contributor to the evolving national clean energy mix through such programs and initiatives as:

- Nuclear power loan guarantees
- The Inflation Reduction Act's (IRA's) clean nuclear electrical, and hydrogen incentives
- The Bipartisan Infrastructure Law (BIL)
- Near-term DOE funding opportunities related to nuclear-based hydrogen hubs and nuclear-integrated hydrogen demonstration projects
- Laboratory support of commercial industries exploring methods to leverage clean nuclear electricity and steam to transition away from carbon-intensive energy sources as part of environmental, social, and governance (ESG) sustainability initiatives.

Given that multiple industrial facilities are located in proximity to Gulf Coast NPPs with high existing demand for heat and hydrogen, leveraging the reliable and continuous heat- and electricity-generation capabilities of nuclear power represents a unique nexus to develop nuclear-integrated hydrogen production in support of economically feasible flexible power operations. This synergy not only aligns with global decarbonization goals, but also positions NPPs as trailblazers in fostering sustainable energy solutions. The following subsections provide a brief overview of the main sections of this report, including hydrogen market analysis, a discussion on available production tax credits (PTCs), and hydrogen infrastructure.

1.1 Overview of Industries and Light Water Reactors in the United States

1.1.1 U.S. Light Water Reactors

The U.S. nuclear-generating fleet is based on LWR technology, using ordinary water as both coolant and neutron moderator. Two main types of LWRs are in operation: pressurized water reactors (PWRs) and boiling-water reactors (BWRs). PWRs maintain water at high-pressure to prevent boiling while BWRs allow water to boil directly, both producing steam for electricity generation. LWR technology's extensive use is due to its proven safety record, operational efficiency, and capacity to generate a substantial portion of the country's electricity while minimizing greenhouse gas (GHG) emissions collectively and individually. LWR technology in the U.S. has continually evolved to enhance safety and efficiency, with stringent regulations and robust operational practices ensuring secure reactor operation. Collectively, LWRs contribute significantly to the nation's electricity, with their individual and combined capacity playing a crucial role in meeting the country's baseload energy needs. Discussions about the future of LWRs involve considerations for new reactor designs, advanced safety features, and integration into a diverse energy landscape focused on clean and sustainable sources. The domestic LWR fleet is depicted in Figure 2. This fleet spans the entirety of the U.S. and has a total net generating capacity of 95,835 MWe (approximately 19% of the total annual U.S. electricity generation).

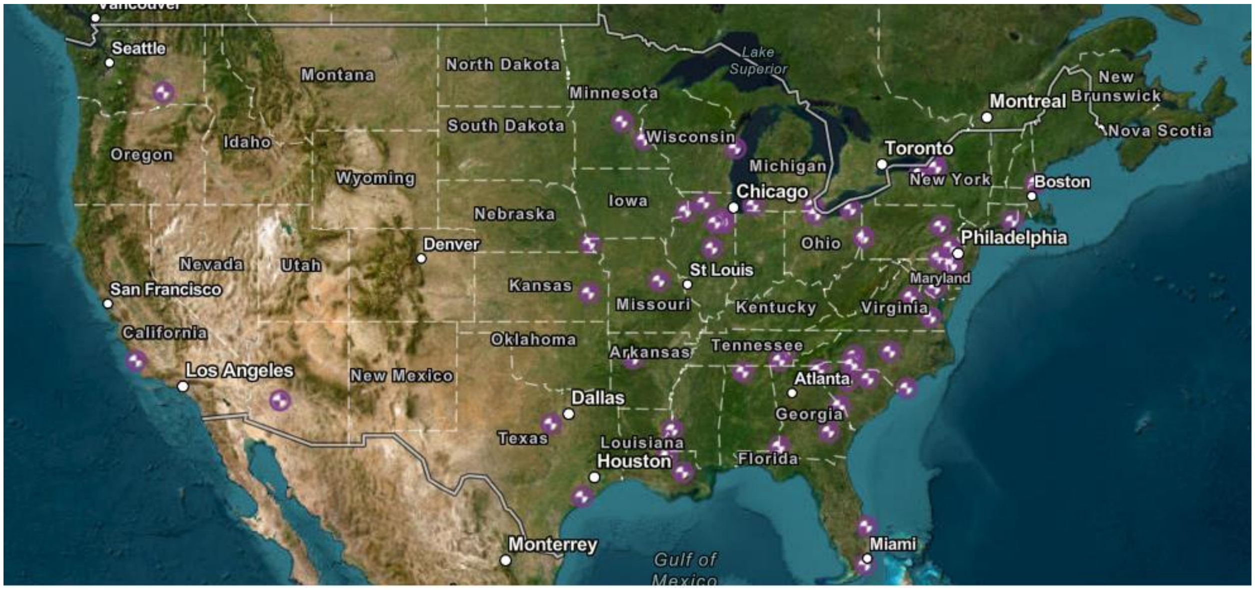


Figure 2. Map of U.S. nuclear plants as of July 2023. [1]

1.1.2 Possible Industrial Markets for Light Water Reactors

The industrial landscape of the U.S. Gulf Coast presents a strategic opportunity for the integration of NPPs in non-traditional grid-based electrical generation roles, particularly in in support sectors like petrochemicals, refining, and manufacturing. This region is home to a significant concentration of energy-intensive industries that demand a stable and substantial power supply (to support electrical and heating-based processes). Nuclear power, with its capacity for continuous and reliable electricity generation, can serve as a cornerstone for meeting the energy needs of these industries. In particular, the Gulf Coast's extensive petrochemical and refining facilities, which are crucial for the nation's energy infrastructure, can benefit from the constant and low-emission power that nuclear energy provides.

The integration of nuclear power into the Gulf Coast's industrial market not only enhances energy security, but also contributes to the region's economic competitiveness. By providing a consistent and sustainable energy source, nuclear power can support the growth and expansion of existing industries and attract new investments. Additionally, as current carbon-intensive Gulf Coast industries continue to focus on improved environmental stewardship, nuclear energy's low carbon footprint aligns with broader goals of reducing GHG emissions and promoting cleaner energy solutions in the industrial sector. Overall, the integration of NPPs in the U.S. Gulf Coast holds a potential to drive economic development, enhance energy resilience, and foster a more-sustainable industrial landscape.

1.1.2.1 Hydrogen

Nuclear energy stands as a key untapped source to produce clean hydrogen, offering a sustainable solution that extends benefits across various sectors. Through processes like high-temperature steam electrolysis (HTSE) or thermochemical water splitting, nuclear reactors can efficiently generate green hydrogen, free from carbon emissions. It is also noted that nuclear-integrated hydrogen production by HTSE or LTE is of high purity compared to the predominant hydrogen-production technology of steam methane reforming (SMR). This creates a unique high-purity product required by some businesses that must further purify hydrogen by SMR today. Nuclear-integrated clean hydrogen holds immense potential in sectors such as industry and energy storage, serving as a versatile and low-carbon energy carrier. In industrial applications, clean hydrogen acts as a valuable feedstock for processes like ammonia production and steel manufacturing, enabling the decarbonization of these traditionally carbon-intensive sectors. Moreover, the role of clean hydrogen extends to energy storage and grid balancing. Hydrogen can be stored and later used to produce electricity when demand is high, thus addressing the intermittent challenges associated with renewable energy sources. The integration of nuclear energy into clean hydrogen production is a cornerstone in fostering a sustainable energy landscape, driving innovation, and supporting the transition to a low-carbon future across multiple sectors.

1.1.2.2 Refineries

Nuclear energy has the potential to serve as a valuable utility in refineries, offering a reliable and continuous source of heat and power essential for various refining processes. The steam generated by nuclear reactors can be used for preheat, fractionation, power delivery, and thermal cracking via delayed coking. The stable and consistent heat output from nuclear reactors enhances the efficiency and predictability of these processes, contributing to increased productivity in refineries. By integrating nuclear energy as a utility in refineries, not only can energy-intensive processes be powered with low-carbon electricity, but refineries can also transition towards more-sustainable and environmentally friendly practices.

1.1.2.3 Petrochemicals and other basic chemicals

Nuclear energy holds the potential to serve as a crucial utility in the basic chemical and petrochemical industries, providing a stable and abundant source of energy in the production of basic chemicals like ammonia and methanol. Furthermore, in the petrochemical industry, nuclear energy can play a key role in supplying high-temperature heat for processes such as steam cracking in the production of ethylene. Steam cracking is pivotal for breaking down hydrocarbons into valuable chemical building blocks like ethylene and propylene. The consistent and substantial heat output from nuclear reactors enhances the efficiency of these energy-intensive processes, providing a more-sustainable energy source relative to conventional fossil fuel-based alternatives. Integrating nuclear energy as a utility in both chemical and petrochemical production aligns with the industry's pursuit of cleaner and more environmentally responsible practices, contributing to a more sustainable future for chemical manufacturing.

1.1.2.4 Natural gas processing

Nuclear energy can play a transformative role in natural gas processing, particularly in enhancing the efficiency of various steps involved in the extraction and refinement of natural gas. The high-temperature heat generated by nuclear reactors can be employed in processes like SMR, where natural gas is converted into hydrogen for various industrial applications. Nuclear-powered SMR offers a low-carbon alternative to traditional methods, contributing to the production of hydrogen without associated GHG emissions. Moreover, nuclear energy can facilitate carbon-capture and utilization (CCU) initiatives in natural gas processing. The generated high-temperature steam can be employed in chemical absorption processes to capture and subsequently use or store carbon-dioxide emissions from the gas streams. This integration aligns with the industry's efforts to reduce carbon footprints and address environmental concerns associated with natural gas extraction and processing. By serving as a reliable source of high-temperature heat, nuclear energy enhances the overall efficiency of natural gas processing, providing an opportunity to mitigate environmental impacts and reduce the industry's carbon intensity. The integration of nuclear power into natural gas processing aligns with the broader goal of transitioning towards cleaner and more-sustainable energy solutions in the oil and gas sector.

1.1.2.5 Iron and steel

Nuclear energy can revolutionize the iron and steel industry by providing a clean and abundant source of high-temperature heat required to produce steel. The conventional method of steelmaking, blast-furnace (BF) ironmaking, relies heavily on coal, resulting in significant carbon-dioxide emissions. Nuclear energy offers an alternative through a process known as direct reduction, where nuclear heat is used to convert iron ore into metallic iron without the need for carbon-intensive coke. This method reduces carbon emissions and increases the overall energy efficiency of the steel-production process. In summary, the incorporation of nuclear energy in the iron and steel industry holds the promise of significantly reducing carbon emissions, enhancing energy efficiency, and fostering the development of more-sustainable and environmentally responsible practices in steelmaking.

1.1.2.6 Ammonia

Nuclear energy can play a transformative role in ammonia production, offering a clean and efficient alternative to traditional methods. In the Haber-Bosch process, which is central to ammonia synthesis, nuclear heat can replace or complement fossil–fuel-derived heat sources, providing the high temperatures and pressures required for the conversion of nitrogen and hydrogen into ammonia. This nuclear-powered approach significantly reduces the carbon footprint associated with ammonia production, contributing to a cleaner method of meeting the global demand for this essential chemical. Moreover, nuclear energy can support the production of green or low-carbon hydrogen, a key feedstock for ammonia synthesis. Through processes like HTSE, nuclear reactors can generate hydrogen with minimal GHG emissions. This "green hydrogen" can then be used in the Haber-Bosch process, further enhancing the environmental profile of ammonia production. By integrating nuclear energy into ammonia production, the industry has the potential to transition towards a more sustainable and climate-friendly approach, aligning with global efforts to reduce emissions and promote cleaner energy solutions in the chemical manufacturing sector.

1.1.2.7 Pulp and paper

Nuclear energy can bring about positive changes in the pulp and paper industry by providing a reliable and sustainable energy source for key processes. In the pulp-production stage, nuclear power can be harnessed to generate high-temperature steam, crucial for the digestion and bleaching of wood fibers. This alternative energy source offers a cleaner and more-efficient way to produce the heat necessary for these energy-intensive steps, reducing the reliance on fossil fuels and decreasing associated carbon emissions. Furthermore, nuclear energy can contribute to the production of biofuels used in the pulping process. Through processes like biomass gasification or pyrolysis, nuclear heat can facilitate the conversion of organic waste materials into biofuels. These biofuels, when integrated into the pulp and paper production process, replace traditional fossil fuels, reducing the industry's environmental impact. By incorporating nuclear energy as a sustainable utility in the pulp-and-paper industry, the sector can enhance its energy efficiency, decrease reliance on non-renewable resources, and contribute to overall environmental stewardship. This approach aligns with the broader trend in industries to transition towards cleaner and more-sustainable energy solutions.

1.2 Hydrogen-Production Analysis

1.2.1 Hydrogen Technologies

1.2.1.1 High-temperature steam electrolysis

HTSE is an innovative method for hydrogen production through the electrolysis of water at elevated temperatures. Unlike conventional electrolysis processes that operate at lower temperatures, HTSE leverages the advantages of increased efficiency by introducing steam into the electrolysis cell. The steam quality produced by NPPs overcomes the latent heat of vaporization and the overall electrically driven process produces higher temperatures for HTSE. At HTSE process temperatures, typically exceeding 700°C, the steam (water) dissociates into hydrogen and oxygen, streamlining the separation process. The elevated temperature not only facilitates the decomposition of steam, but also reduces the electrical energy input required for the electrolysis reaction, making the overall process more energy-efficient. This technique becomes particularly advantageous when coupled with a medium-temperature heat source, such as nuclear energy. By integrating nuclear heat, the HTSE process gains a sustainable energy supply contributing to the production of hydrogen with a lower environmental impact. This electrolysis water source in the form steam from nuclear energy presents a promising avenue for advancing hydrogen production methods via HTSE vs LTE, aligning with the global push for cleaner and more sustainable energy solutions.

1.2.1.2 Low-temperature electrolysis

Low-temperature steam electrolysis is a method for hydrogen production that involves the electrolysis of water at relatively modest temperatures. In contrast to HTE, which operates at elevated temperatures, the LTE typically occurs at temperatures below 100°C. In this process, liquid water is introduced into the electrolysis cell, where an electrical current initiates the separation of water into hydrogen and oxygen. While electrical-only LTE is generally less energy-efficient than its high-temperature counterpart, it can be implemented using a variety of renewable energy sources without the need for a steam-generation source. The lower operational temperatures make LTE suitable for applications where high-temperature conditions are impractical. However, this method still offers a sustainable means of hydrogen production, particularly when powered by renewable energy sources like solar or wind, albeit one that is intermittent in nature. Despite its lower efficiency relative to high-temperature alternatives, LTE plays a role in advancing the development of clean-hydrogen technologies, contributing to the broader effort to integrate hydrogen as a clean energy carrier in various sectors.

1.3 Hydrogen-Demand Market Analysis

A comprehensive examination of the hydrogen industry—encompassing production, consumption, trends, and market dynamics—was completed surrounding each NPP. Factors like government policies, technological advancements, and the increasing focus on decarbonization initiatives shape the trajectory of the hydrogen industry. Additionally, the analysis assessed the evolving landscape of hydrogen applications, including its role in sectors like transportation, manufacturing, and power generation. Understanding the competitive landscape, investment trends, and emerging opportunities within the hydrogen market is crucial for stakeholders, policymakers, and industry participants alike. As the global community intensifies efforts to achieve a sustainable energy future, hydrogen market analysis serves as a valuable tool for informed decision-making and strategic planning in this dynamic and rapidly evolving sector.

1.4 Production Tax Credit Opportunity for Light-Water Reactors

LWRs could significantly benefit from the PTC aimed at promoting clean energy generation, including hydrogen production. This PTC provides financial incentives for each unit of energy produced from renewable sources, and its extension to include low-carbon hydrogen production can make nuclear-powered electrolysis more economically viable. By leveraging the PTC, operators of LWRs can offset some of the high initial costs associated with setting up hydrogen-production facilities, thereby lowering the overall cost of hydrogen production. This financial support can make hydrogen produced via nuclear energy competitive with hydrogen derived from fossil fuels, accelerating the adoption of nuclear-powered hydrogen-production technologies.

1.5 Avoided Cost of Carbon

Integrating LWRs into hydrogen production illustrates the substantial opportunities available through avoided carbon costs by providing a comparison of low-carbon alternative to conventional hydrogen-production methods. Traditional hydrogen production, primarily through SMR, emits significant amounts of carbon dioxide (~10 kg of CO_2/kg-H_2). By utilizing nuclear power from LWRs to produce hydrogen via electrolysis, these emissions can be drastically reduced to less than 1 kg of CO_2/kg-H_2. Electrolysis, especially when powered by nuclear energy, is a zero-emission process because it involves splitting water into hydrogen and oxygen without releasing GHGs. This shift could lead to substantial carbon savings, helping industries meet stringent emissions targets and reducing the overall carbon footprint of hydrogen production.

The avoided cost of carbon through LWR-integrated hydrogen production extends beyond direct emissions reductions. Nuclear-powered hydrogen production can stabilize and decarbonize sectors that are hard to electrify, such as industrial manufacturing, heavy transport, and certain chemical processes. By providing a steady and reliable supply of low-carbon hydrogen, LWRs can facilitate the transition of these sectors from fossil fuels to cleaner alternatives. This transition not only reduces operational emissions, but also helps in achieving broader climate goals. The economic benefits of avoided carbon costs include future potential savings on carbon taxes, improved regulatory compliance, and enhanced market competitiveness for industries adopting cleaner technologies.

Moreover, the integration of LWRs with hydrogen production aligns with global and national policies aimed at reducing carbon emissions. Countries worldwide are setting ambitious targets to achieve net-zero emissions, and clean hydrogen is a critical component of many decarbonization strategies. In the U.S., government initiatives and incentives increasingly support low-carbon hydrogen projects. By leveraging LWRs for hydrogen production, the U.S. can capitalize on these policy frameworks, attract investments, and stimulate technological advancements in the nuclear and hydrogen sectors. The resultant avoided carbon costs represent both environmental benefits and economic opportunities because industries and regions that lead in low-carbon technologies gain a competitive edge in the evolving global market.

1.6 Nuclear-Integrated Hydrogen Production

This techno-economic assessment (TEA) of nuclear-integrated hydrogen production represents a pivotal exploration into the feasibility and economic viability of harnessing nuclear power for sustainable hydrogen generation. This assessment is based on combining nuclear energy with hydrogen production, using a comprehensive analysis framework to evaluate various factors influencing cost-effectiveness and profitability. In integrating LWRs with hydrogen production, this study aims to shed light on the potential of nuclear power to contribute to the hydrogen economy, addressing critical questions regarding financial feasibility, technological scalability, and environmental sustainability. The TEA provides invaluable insights into the economic landscape of nuclear-integrated hydrogen production, paving the way for informed decision-making and strategic planning in the energy sector.

Previous TEAs have demonstrated the potential for nuclear-integrated hydrogen production, including:

- Xcel Energy’s Prairie Island and Monticello nuclear generating stations. [2]
- A generalized gigawatt-hour HTSE plant integrated with a hypothetical PWR. [3]
- A specification of a reversible solid-oxide system in which the levelized cost of hydrogen (LCOH) was estimated by adopting the cash flow analysis from National Renewable Energy Laboratory (NREL) H2A model with updated direct capital cost (DCC) estimation by adding component-specific costs for each HTSE plant. [4]

Recently a calculation tool has been developed using all these TEAs as a baseline for the calculations. It is called the Nuclear-Integrated Hydrogen Production Analysis (NIHPA) tool. [5][6]

1.7 Potential Opportunity for Heat Demand Proximate to Light-Water Reactors

Potential heat demand from industries near an NPP can potentially be satisfied in whole or in part by an LWR. In addition to providing clean steam and electricity to produce hydrogen, nuclear facilities have the potential to provide thermal energy to industrial partners. An NPP produces a significant amount of heat in the form of saturated steam from the reactor. This has traditionally been dedicated exclusively to electricity generation. Diverting part of this heat in the form of clean steam to meet the thermal demands of nearby industries is a concept known as combined heat and power (CHP) or cogeneration. This integration offers a dual benefit, optimizing the use of energy resources and enhancing the overall efficiency of the nuclear facility. By supplying heat to nearby industries, the NPP becomes an integral component of a broader energy ecosystem, contributing not only to electricity generation, but also meeting the thermal needs of industrial processes. This symbiotic relationship enhances energy efficiency, reduces GHG emissions, and promotes sustainability. Industries with substantial heat requirements, such as those in the manufacturing or chemical sectors, can benefit from a consistent and reliable source of thermal energy, contributing to their operational stability. The influence of potential heat demand from industries underscores the importance of holistic energy planning and synergies between different sectors. Such integration aligns with the broader goal of creating energy systems that are not only reliable and resilient, but also environmentally conscious. As industries increasingly focus on sustainable practices, the collaborative use of clean heat from NPPs presents a strategic opportunity to enhance the overall efficiency and environmental performance of the energy landscape.

The specific use of clean nuclear-generated steam could reduce industrial heating emissions by reducing or eliminating dependence on heat sources such as natural gas. NPP steam can be used in many industries, including oil refining and chemical and ammonia production. [7] Cogeneration of electricity by diversion of thermal energy transported to an industrial partner can help to decarbonize hard-to-decarbonize sectors such as major industry. Industrial heating accounts for 9% of total U.S. carbon emissions. [8]

NPPs are unique in their ability to produce large amounts of always-available low-carbon heat that can service industrial steam-heat users for various functions. Extracting NPP steam upstream of high- and low-pressure turbine generators improves energy efficiency by approximately 1/3 over that of traditional turbine-generator overall-system electrical conversion. Because of this, nuclear heat to industry can be competitive with other clean-energy solutions for decarbonizing industry.

Based on a preliminary review of NPP proximity to high concentrations of industrial steam users, a preliminary analysis was completed on the heat demands surrounding the Waterford 3 plant and the potential costs of steam transport to these surrounding industries.

This report assumed that NPP-provided industrial-use steam was extracted from the main steam system of a standard 1200-MW PWR. [9] The assumed plant system-extraction location (main steam system) was selected to maximize the steam pressure and temperature available to the industrial user. This main-steam extraction case used select information from a design report from Sargent and Lundy (S&L) that assesses the coupling of a large-scale hydrogen-production facility with a commercial power plant [9] through relatively low-energy extraction of steam after the high-pressure turbine (cold-reheat steam) via a reboiler heat-transfer design. Although the above referenced design was based on the lower steam-extraction needs of a coupled NPP, it included common reboiler elements and general piping and component, pipe-support, and insulation cost estimates, which were scaled for high-pressure direct main-steam extraction applicability and used for convenience in estimating costs for heat transfer via the main-steam-system extraction point. With regard to the nuclear-safety aspects associated with extracting steam to an off-site user, Remer et al. [9] previously evaluated the extraction of steam and electrical power from an LWR-based NPP and concluded that up to 500 MW_e and 100 MW_{th} nominal extraction levels, no adverse impacts on reactor operations and control would be seen. It is expected that detailed main-steam-extraction cases could exceed these preliminary combined plant-electrical and steam-diversion findings. A more-detailed analysis on this topic is left for future work.

This report concludes that the heat demand from existing industries surrounding Waterford NPP (and potentially other fleet NPPs) represents a potentially viable business opportunity that can have a substantial influence on the overall clean-energy dynamics of the region. Preliminary review indicated that depending on the distance between Entergy NPP steam providers and potential industrial users, high-pressure and temperature steam extraction and transport could potentially help optimize the utilization of energy resources and enhance the overall profitability of the nuclear facility.

1.8 Overview of Hydrogen Infrastructure Close to U.S. Light-Water Reactors

LWRs in the United States present significant opportunities when situated near such established hydrogen infrastructure as pipelines and storage facilities. One primary advantage is the potential for efficient and continuous hydrogen production. LWRs can generate substantial amounts of electricity that can be used to power electrolysis processes. By harnessing nominal levels of NPP electrical and steam diversion, LWRs can contribute to a more stable and cost-effective hydrogen supply, fostering the growth of a hydrogen economy.

Additionally, proximity to hydrogen pipelines and storage facilities can enhance the integration of nuclear-powered hydrogen production into the existing energy landscape. Having access to established hydrogen pipelines means that the produced hydrogen can be easily transported to industrial users, fueling stations, or other end-users without the need for significant additional infrastructure investment. Similarly, nearby storage facilities enable the buffering of hydrogen supply, accommodating fluctuations in both production and demand. This can lead to increased resilience and reliability in hydrogen supply chains, making hydrogen a more-viable and attractive energy carrier.

The current pipelines and storage near these reactors are more established in the Gulf Coast. However, ongoing research and industry efforts are both assessing and developing the infrastructure needed to expand clean-hydrogen adoption. This includes evaluating the feasibility of repurposing existing natural gas pipelines for hydrogen transport and constructing new pipelines specifically designed for hydrogen. Storage solutions are also being explored, with options such as compressed-gas storage, liquid-hydrogen tanks, and the potential for underground storage in salt caverns or depleted gas fields near nuclear sites. These storage methods are crucial to ensure a steady hydrogen supply and balance production with variable demand.

2. SELECTION OF LEADING PLANTS FOR HYDROGEN INTEGRATION

2.1 Light-Water Reactors in the Gulf Coast Region

The domestic LWR fleet, presented in Figure 2, spans the entirety of the U.S. It has a total net capacity of 95,835 MWe, which provides approximately 19% of total annual U.S. electricity generation. Of this total capacity, about 18% of energy generation is concentrated in the Gulf Coast region as shown in Table 1[11]. The smallest station in the region is Turkey Point, located in Florida, producing 1658 MWe from 5288 MWth. The largest station is Browns Farley Nuclear Plant in Alabama, producing 3610 MWe (~10,374 MWth) from three 1,200 MWe reactors.

The Gulf Coast region is home to several LWRs that play a vital role in contributing to the area's energy mix. These reactors, including facilities such as the South Texas Project in Bay City, have been instrumental in providing a steady and substantial supply of electricity to support the region's diverse industrial and residential markets. LWRs, with proven safety records and efficient electricity generation, are particularly well-suited for meeting the energy demands of the Gulf Coast, where industries such as petrochemicals and refining require reliable and continuous power. The robust infrastructure of LWRs in this region has contributed, not only to energy security, but also to the economic development and growth of the Gulf Coast. The strategic placement of LWRs in the Gulf Coast underscores their significance in supporting the region's energy-intensive activities. With a focus on sustainability and reducing environmental impact, these LWRs contribute to the Gulf Coast's efforts to meet energy demand while minimizing carbon emissions. As the Gulf Coast navigates its energy future, the presence of these reactors remains integral to ensuring a resilient, clean, and secure energy supply for the Gulf Coast's industrial and residential needs.

Table 1. LWRs in the Gulf Coast. [11]

NPPs in Gulf Coast	Thermal Capacity (MW-th)	Plant Design Electricity Capacity (Mwe-ac)	Thermal Efficiency	Capacity Factor (2022)
Browns Ferry 1	3458	1200	34.70%	90.0%
Browns Ferry 2	3458	1200	34.70%	100.0%
Browns Ferry 3	3458	1210	34.99%	87.3%
Comanche Peak 1	3612	1205	33.36%	88.7%
Comanche Peak 2	3612	1195	33.08%	100.0%
Farley 1	2775	874	31.50%	72.7%
Farley 2	2775	883	31.82%	93.6%
Grand Gulf 1	4408	1401	31.78%	73.1%
River Bend 1	3091	967	31.28%	100.0%
Saint Lucie 1	3020	981	32.48%	91.3%
Saint Lucie 2	3020	987	32.68%	96.2%
South Texas 1	3853	1280	33.22%	100.0%
South Texas 2	3853	1280	33.22%	90.8%
Turkey Point 3	2644	837	31.66%	100.0%
Turkey Point 4	2644	821	31.05%	91.3%
Waterford 3	3716	1168	31.43%	77.4%

2.2 Hydrogen Demand Market Analysis

The hydrogen market is analyzed at both the national and regional levels. Section 2.2.1 discusses the U.S. hydrogen market, size, and location as well as the life cycle CO_2-emissions reduction associated with nuclear-produced hydrogen for these markets.

2.2.1 U.S. Hydrogen Market and Life-Cycle Assessment of Carbon-Reduction Potential

National hydrogen demand is estimated using data from multiple sectors—e.g, transportation, manufacturing, and power generation. Some of this demand exists now while the some represents potential future demand. All nuclear-integrated hydrogen demand is considered potential because existing demand is served by existing carbon-intensive hydrogen-production (primarily SMR) facilities that would have to be displaced in order to access the demand. Specific future applications include fuel-cell electric vehicles, co-firing hydrogen with natural gas in combustion turbines, petroleum refineries, direct-reduced iron (DRI) for metals, ammonia and fertilizer production, and synthetic fuel production. The methodology for determining the hydrogen demand is in Table 2. For more information, see the detailed account of these computations in the 2021 report. [2]

Table 2. Summary of assumptions and data sources for computation of future potential hydrogen demand in the U.S. [2]

End-Use	Main Assumptions and Data Sources	Background Information, If Any	Offset in CO_2 Emissions
Hydrogen blending with natural gas in combustion turbines (CTs)	Potential demand is estimated for hydrogen by assuming it can be used by natural gas CTs with a volume ratio of 30% hydrogen blended with 70% natural gas. Electricity generators were identified using the data sets from the EIA-860 and EIA-923 forms describing electricity-generator facility locations and fuel use.	The clean hydrogen produced from the nuclear energy can be injected into natural gas pipelines for use as a low-carbon green component of a natural gas/hydrogen fuel mix for general heating or for exclusive use in CTs for power generation.	The life-cycle GHG emissions are estimated at 493-g CO_2e/kWh when using only natural gas as the feed, and 442-g CO_2e/kWh for the mixture of 30% hydrogen and 70% natural gas by volume for different CTs technology shares.
Petroleum refineries	The crude inputs are estimated to increase from 16 to 18 Mbbl/d (with a steeper increase of 9% from 2015 to 2021 and then a more-gradual increase to 2050). Gasoline output decreases from 8 to 6 Mbbl/d, diesel output increases slightly, and average jet-fuel output increases roughly 0.5 Mbbl/d, from about 1.7 to 2.2 Mbbl/d. Based on these assumptions, in addition to the internal hydrogen production via catalytic reforming of naphtha, the total U.S. hydrogen demand for petroleum refining is estimated as 5.9 MMT/year in 2017 and 7.5 MMT/year in 2050.	Hydrocracking is used to produce diesel from heavy crude, and hydrotreating is used to remove sulfur from feed, intermediate, and product streams. Hydrogen is used in these two processes. This hydrogen can be produced internally in a refinery via catalytic reforming of naphtha. Hydrogen produced from the NPPs can be substituted for or can complement the internally produced hydrogen.	The well-to-gate CO_2e emissions for H_2 produced from natural gas SMR and HTSE (nuclear) are estimated to be 9.28-kg CO_2e/kg H_2 and 0.15-kg CO_2e/kg H_2, respectively.

End-Use	Main Assumptions and Data Sources	Background Information, If Any	Offset in CO_2 Emissions
DRI for metals refining and steel production	DRI process using 100% hydrogen as the reducing agent requires up to 100 kg H_2/tonne of steel (i.e., a mass ratio of approximately 10%). However, using hydrogen in a blend with natural gas up to 30/70 ratio by energy to produce DRI would not require modifications to the original technology that was developed to work solely with natural gas. The potential hydrogen demand for DRI was based on using 30% hydrogen and 70% natural gas on an energy basis.	The DRI is a process developed by Midrex Technologies, Inc., for producing high-purity iron from ore at temperatures below the melting point of iron by reducing the iron oxide ore and driving off oxygen in a reactor using a reducing agent. The reducing agent can be carbon coke, hydrogen, or syngas. DRI is converted to steel in an electric arc furnace (EAF).	The GHG emissions from each respectively is 1.97-tonnes eq.CO_2 /MT steel from a BF, 1.47-ton eq.CO_2 /MT steel from an EAF using 100% natural gas, 1.28-MT eq.CO_2 /MT steel from EAF using 70% natural gas and 30% nuclear H_2, and 0.99-MT eq.CO_2/MT steel from EAF using only nuclear H_2.
Ammonia and fertilizers	A 25% increase in hydrogen demand for NH_3 production between 2017 and 2024 is estimated. Domestic hydrogen demand for NH_3 production beyond 2024 is assumed to grow by another 15% by 2050.	Ammonia is produced by the Haber-Bosch process, in which hydrogen and nitrogen separate from the air react. The hydrogen is usually produced from natural gas react via the SMR process. This hydrogen can be substituted for using clean hydrogen produced via nuclear energy.	The conventional pathway produces about 2.55 MT CO_2/MT NH_3 while the nuclear for both H_2 and air separation unit (ASU) produce 0.06 MT CO_2/MT NH_3, respectively, on a life-cycle basis.
Synthetic fuels	Synthetic fuels can be used for carbon-intensive energy-sector end uses like transportation. Hence, the production and use of synthetic fuels can significantly support the efforts toward decarbonization. The hydrogen demand for synfuel production can be estimated based on the stoichiometric 1:3 mole ratio of CO_2 to H_2 that is required for the synthesis of Fischer-Tropsch (FT) diesel or dimethyl ether.	Synthesis gas (syngas) is a mixture of carbon monoxide and hydrogen. It is called syngas because these two molecules can be used to synthesize synthetic fuels (synfuels) and chemicals (synchemicals). Significant quantities of high-purity CO_2 are generated in such industry processes as ethanol production, SMR used for hydrogen production from natural gas for refining, and ammonia production. These high-concentration CO_2 sources present opportunities to produce synfuels and synchemicals using a wide variety of pathways while minimizing the cost and energy penalty to capture CO_2 relative to other dilute CO_2 sources (e.g., from flue gases of coal and natural gas power plants).	The GHG emissions per megajoule for various fuels like gasoline, jet-fuel, diesel fuel, and FT fuel (using nuclear H_2) are 93, 86, 91, and 9 g CO_2 eq./MJ, respectively.

2.2.2 Overview of Total Hydrogen Demand in the Gulf Coast Region

For market analysis, potential hydrogen demand is categorized into three tiers. Tier 1 covers the facilities that currently use hydrogen that could be replaced with nuclear-produced hydrogen, including refineries and the ammonia industry. Tier 2 includes demand for industries that could use blends of hydrogen with some retrofitting: steel production using DRI and electricity generation from natural gas. Tier 3 includes potential greenfield projects like e-fuel production for gasoline, jet fuel, and methanol. Figure 3 shows potential demand within 100 miles of NPPs and some power plants, such as Waterford, Riverbend and South Texas, that have significant demand.

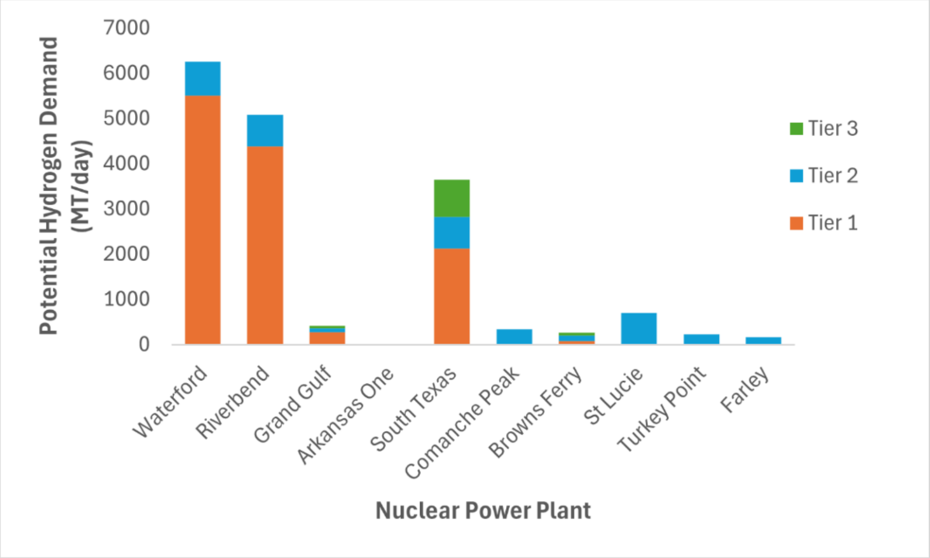


Figure 3. Potential demand of hydrogen around NPPs in the Gulf Coast according to different tiers.

2.3 Hydrogen Infrastructure in the Gulf Coast Region

2.3.1 Hydrogen Pipelines

Pipelines are ideal for transporting large volumes of hydrogen from the point of production to large market demand centers, particularly in areas with high regional demand and density, such as the U.S. Gulf Coast region. This region is home to petroleum refining and petrochemical production which currently require over 3.5 MMT/yr of hydrogen demand [12]. This regional demand is expected to increase as the demand for clean refined products and chemicals and synthetic fuels increase. [13]

The U.S. has over 1,600 miles of dedicated hydrogen pipeline to serve the national hydrogen demand. The majority of the hydrogen pipeline network, over 1,000 miles of hydrogen pipelines [12], is located in the Gulf Coast region as exhibited in Figure 4.

Figure 4. Hydrogen pipelines in the Gulf Coast region. [14]

As the demand for clean hydrogen increases in the region, the production of hydrogen from electrolysis with nuclear power becomes a viable supply option. Several large nuclear reactors are located within a 2–50 mile range of existing hydrogen pipelines. These reactor locations include the Entergy reactors at Waterford (Louisiana), Riverbend (Louisiana), Grand Gulf (Mississippi), and the South Texas Project (Texas). The distances between nuclear reactors and the nearest hydrogen pipeline are shown below in Table 3.

Table 3 Distance from NPP to nearest hydrogen pipeline. [15]

NPP	Distance (km) to nearest hydrogen pipeline
Waterford	0.3
Riverbend	32.0
Grand Gulf	169.8
STP	40.6
CP	431.2

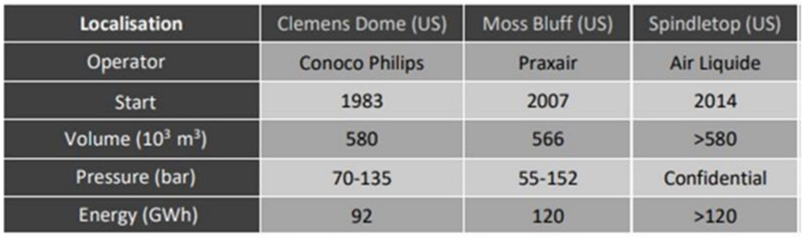
2.3.2 Hydrogen Storage

Hydrogen storage can be coupled with hydrogen production to manage system dynamics to meet hydrogen-demand requirements. The storage type and capacity will depend on charge/discharge cycles and cycle depth. High-pressure gas storage and liquid storage can be tailored to short-term and short-duration hydrogen demand. However, supply-and-demand dynamics of large hydrogen systems required for the Gulf Coast region will need a large-capacity geologic storage cavern. This type of system enables adjustments for disruptions in the hydrogen production units of the system. The Gulf Coast hydrogen pipeline network has several geologic storage caverns that integrate with hydrogen pipeline network, as shown in Figure 5.

2.3.3 Geological Hydrogen Storage

Geologic storage systems enable adjustments for disruptions in the hydrogen-production units of the system. Also, this system would enable the storage of hydrogen produced through the Gulf Coast NPPs and connected through the hydrogen-pipeline network. Usually, large demand centers associated with the hydrogen-pipeline network require sustainable and uninterruptable hydrogen supply. Geologic storage offers this buffer to the network to insure the supply.

The Gulf Coast hydrogen-pipeline network has several geologic storage caverns that integrate with hydrogen pipeline network, as shown in Figure 5.



Localisation	Clemens Dome (US)	Moss Bluff (US)	Spindletop (US)
Operator	Conoco Philips	Praxair	Air Liquide
Start	1983	2007	2014
Volume (10^3 m^3)	580	566	>580
Pressure (bar)	70-135	55-152	Confidential
Energy (GWh)	92	120	>120

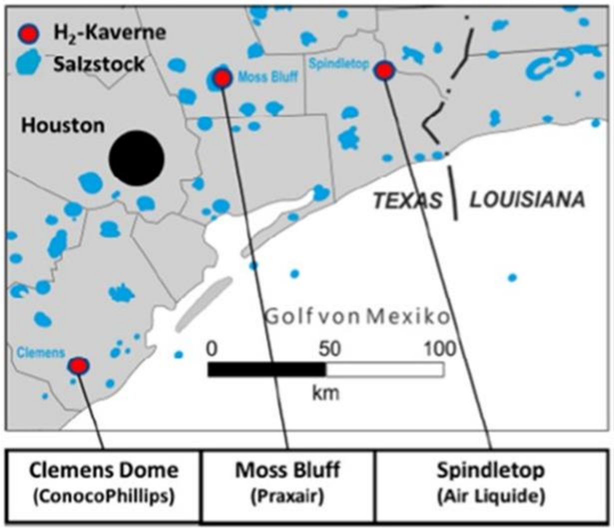


Figure 5. Hydrogen geologic storage in the Gulf Coast. [16]

The potential hydrogen supply from electrolytic hydrogen produced from nuclear power can be integrated with hydrogen storage in the Gulf Coast region. Also, this region has a potential for increased hydrogen storage, as evidenced in a Sandia National Laboratories study [17]. This study found that current storage can be expanded to other parts of the region, as shown in Figure 6.

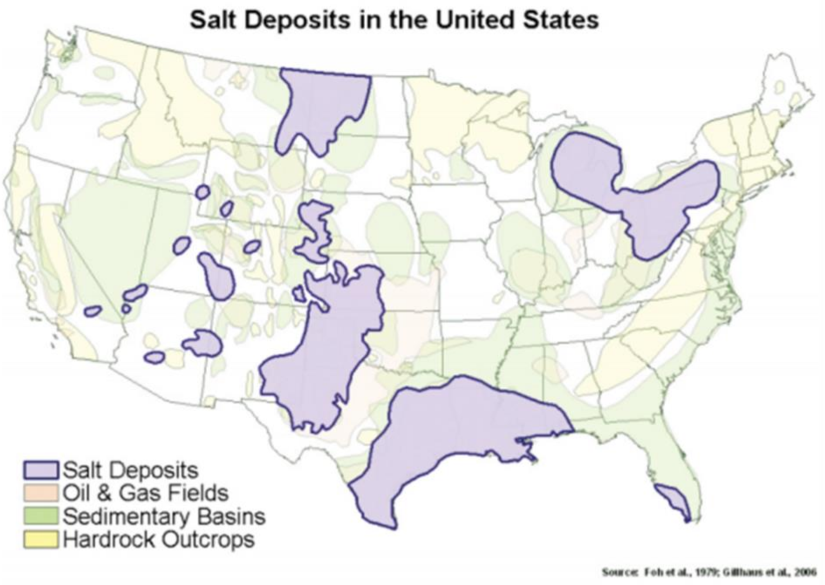


Figure 6. Potential U.S. geologic storage [17].

2.4 Justification of Selected LWR Case Study

The selection of LWRs in the Gulf Coast for hydrogen integration is driven by several strategic criteria, starting with the capacities of the reactors themselves. Notably, reactors sites such as Comanche Peak in Texas and the South Texas Project boast high capacities, each with over 2,400 MW of generating power. These substantial capacities enable reactors to produce significant amounts of hydrogen through electrolysis processes. The ability to generate hydrogen at nominal scale is essential for meeting the large hydrogen demand of users in the Gulf Coast regions. Larger-capacity reactor sites are more likely to be capable of meeting the high demand presented by nearby customers.

Another critical criterion is the existing and potential hydrogen demand in the Gulf Coast, particularly from industrial hubs such as Waterford, River Bend, Grand Gulf, and South Texas. These locations are home to a variety of industries that have substantial hydrogen requirements, including oil refining, chemical manufacturing, and steel production. For instance, the South Texas Project is strategically located near major industrial centers that rely heavily on hydrogen. Additionally, it is soon to be in close proximity (within 2 miles) of a new hydrogen-based methanol facility. By integrating LWRs with hydrogen production capabilities in these areas, the reactors can directly supply hydrogen to nearby industries, reducing transportation costs and enhancing the efficiency of hydrogen delivery. This proximity to high-demand areas ensures that the hydrogen produced is immediately and effectively utilized, supporting the decarbonization efforts of these key sectors.

The extensive network of hydrogen pipelines in the Gulf Coast further supports the integration of LWRs with hydrogen production. The region features the most-comprehensive hydrogen-pipeline infrastructure in the U.S., facilitating the efficient transport of hydrogen from production sites to various end users. This network includes major pipelines that connect industrial hubs across the region, enabling the seamless distribution of hydrogen. For example, Waterford and South Texas are proximate to current hydrogen pipelines. The availability of this infrastructure means that LWRs, once integrated with hydrogen production systems, can readily inject hydrogen into these pipelines. This minimizes the need for additional infrastructure investments and accelerates the deployment and scaling of nuclear-powered hydrogen production. These pipeline-transport networks ensure that nuclear-integrated hydrogen can be delivered to a wide range of industrial customers both quickly and cost-effectively.

Last, the Gulf Coast's hydrogen-storage capabilities play a vital role in the selection process. The region is equipped with advanced storage solutions, including compressed-gas and underground storage in salt caverns. These storage options are crucial for balancing hydrogen supply and demand, especially given variable industrial consumption patterns. By integrating LWRs with these storage facilities—most likely via existing connected pipeline networks—excess hydrogen produced during low-demand periods can be stored and then released during peak demand times. This ensures a continuous and reliable hydrogen supply, which is essential for maintaining stable industrial operations. The ability to store hydrogen effectively enhances the economic feasibility and operational stability of hydrogen production projects, making the Gulf Coast an optimal location for integrating high-capacity LWRs with hydrogen infrastructure.

Based in the criteria described above, this study intends to assess hydrogen and steam opportunities for Waterford, Riverbend, Grand Gulf, South Texas and Comanche Peak NPPs.

3. HYDROGEN DEMAND AT NPPS IN THE GULF COAST

3.1 Potential Hydrogen Demand for the Selected Nuclear Power Plants in the Gulf Coast Region

Relevant extracts from national data on potential hydrogen demand were used to analyze the potential hydrogen demand centers in the vicinity of the Entergy Arkansas Nuclear 1, Waterford 3 Nuclear Generating Station, Riverbend Station, and Grand Gulf Nuclear Station NPPs. Detailed tables of various facilities within 100 miles of each of these NPPs that currently are demanding or potentially will demand hydrogen are provided in Appendix A. Hydrogen demand may not be accessible (owing to constraints like cost, distance, existing contracts with other H_2 suppliers, etc.) even though it may represent current demand. A baseline 500-MW nominal-rated HTEF, producing 351 tonne/day, was assumed for all TEA done under this report. This was based on the successful design conceptualization of such an integrated HTEF, drawing electrical and steam energy off a standardized 1200 MW NPP [9]. In this referenced report, S&L provided preconceptual designs for plant modifications and the impacts of diverting 105-MWth and 500-MWe energy from the NPP to a hydrogen-production facility. The steam-supply design evaluated extraction steam after the high-pressure turbine (cold-reheat steam). PEPSE modeling was used to inform transients and size equipment for thermal extraction. Cost estimates for plant modifications were developed by separation distance. These cost estimates included civil, structural, concrete, mechanical, electrical work, instrumentation, and controls and were used as a basis for estimating the cost of thermal-extraction and electrical-feed equipment. Where hydrogen-pipeline location data were known, they were used specifically in the analyses. Otherwise, natural-gas-pipeline data were used because this may be another source for blending hydrogen with natural gas in the future. Natural gas pipelines in the U.S. are shown in the plots.

3.1.1 Waterford Nuclear Power Plant

The Waterford Steam Electric Station (shown in Figure 7) is an NPP with a rated capacity of 1152 MWe—i.e., the potential to produce more than 600 MT/day of hydrogen—located in Killona, Louisiana. It is a PWR with a thermal capacity of 3716 MW. It generates about 7–10 TWh/yr.

Figure 7. Waterford Steam Electric Station, Unit 3.

The future potential demand for hydrogen from this plant from facilities within 100-miles is 6498 tonnes/day. A more-detailed distribution of facilities that may demand hydrogen from this NPP is shown in Figure 8 and Figure 9. Ammonia production is the largest consumer of hydrogen, followed by refineries. It may be noted that for this NPP, more than half of the total hydrogen demand centers are located within 50 miles.

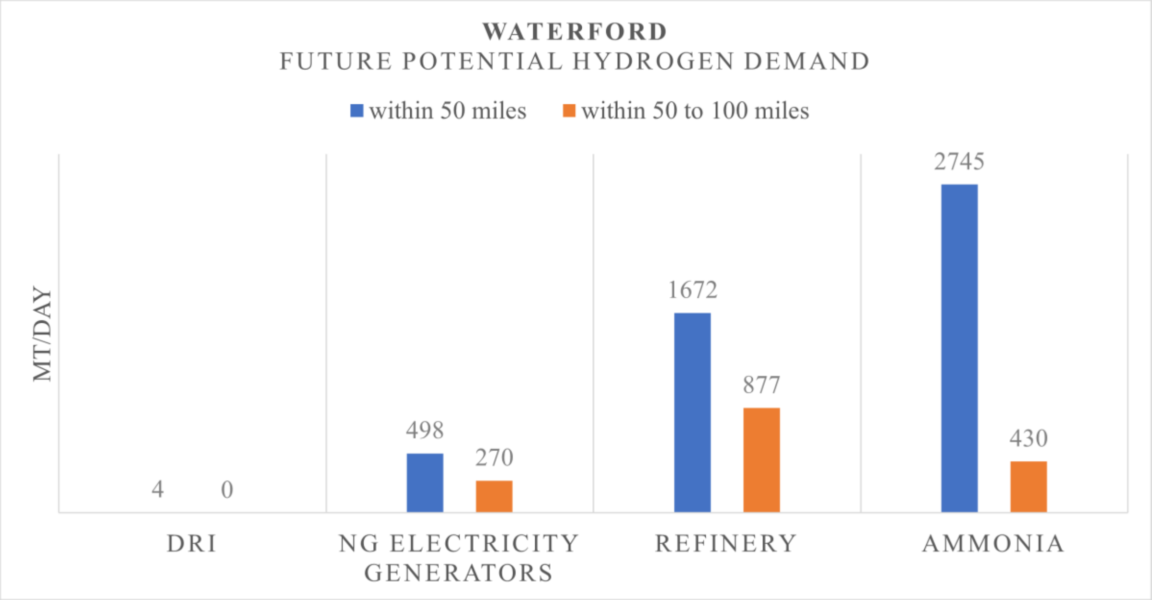
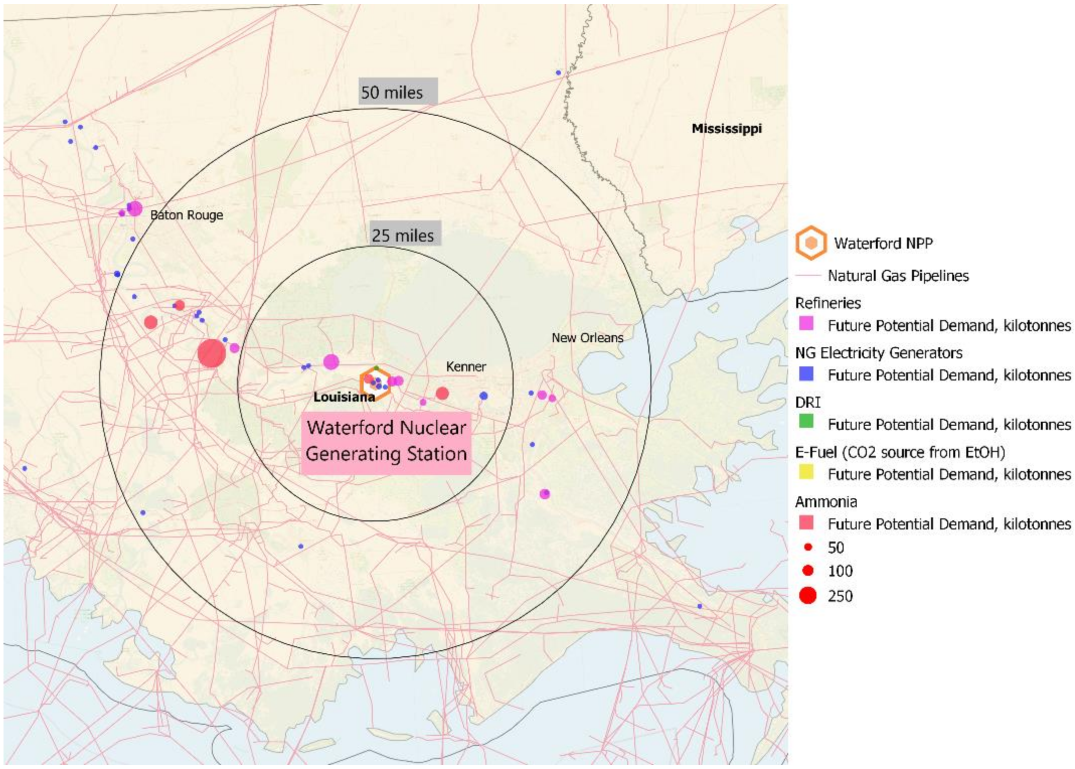
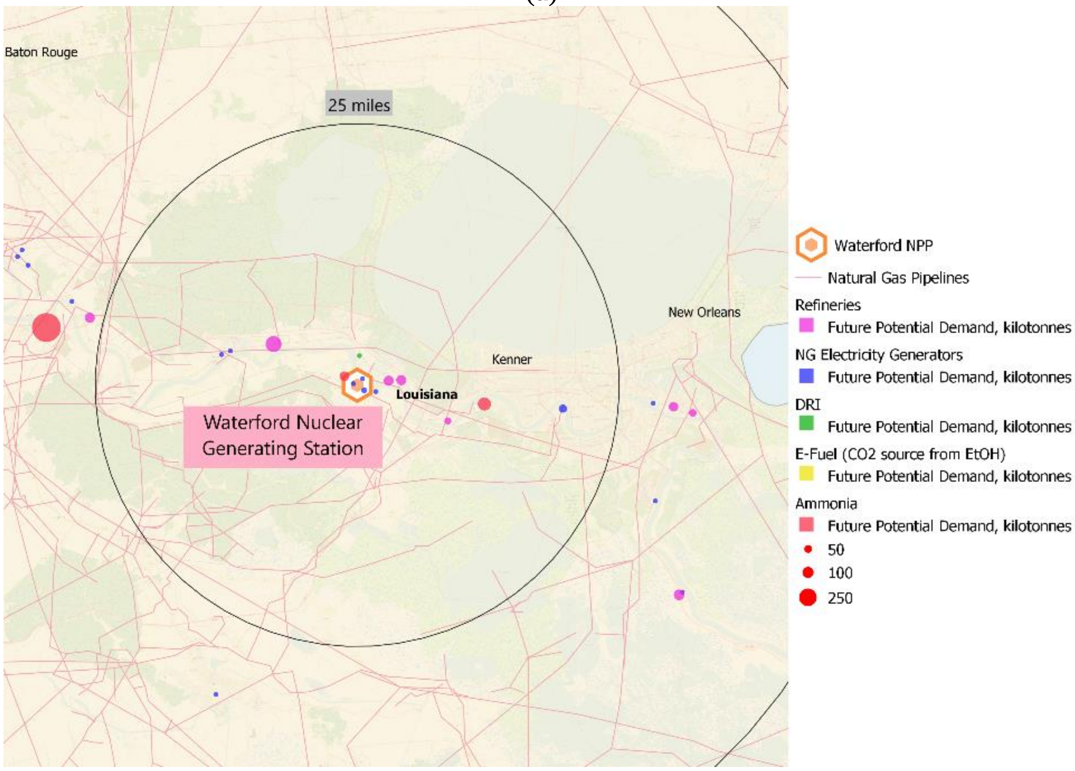


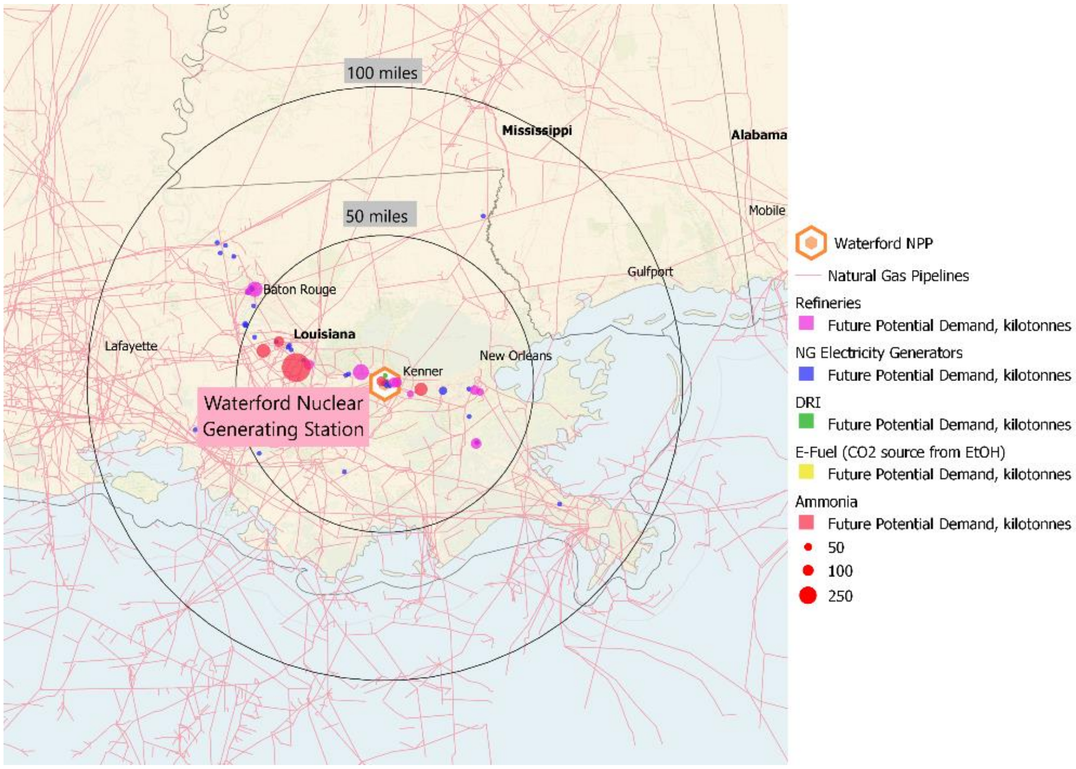
Figure 8. Distribution of future potential demand for hydrogen in the region surrounding Waterford NPP.


50 miles
Mississippi
Baton Rouge
25 miles
New Orleans
Kenner
Louisiana
Waterford Nuclear Generating Station
Waterford NPP
Natural Gas Pipelines
Refineries
Future Potential Demand, kilotonnes
NG Electricity Generators
Future Potential Demand, kilotonnes
DRI
Future Potential Demand, kilotonnes
E-Fuel (CO2 source from EtOH)
Future Potential Demand, kilotonnes
Ammonia
Future Potential Demand, kilotonnes
50
100
250

(a)


Baton Rouge
25 miles
New Orleans
Kenner
Louisiana
Waterford Nuclear Generating Station
Waterford NPP
Natural Gas Pipelines
Refineries
Future Potential Demand, kilotonnes
NG Electricity Generators
Future Potential Demand, kilotonnes
DRI
Future Potential Demand, kilotonnes
E-Fuel (CO2 source from EtOH)
Future Potential Demand, kilotonnes
Ammonia
Future Potential Demand, kilotonnes
50
100
250

(b)



(c)

Figure 9. Centers for hydrogen demand for Waterford NPP (a) in 50 and 25 miles (ab) 25 miles (b) in 25 and 50 miles (c) 50 and 100 miles.

This plant is located close to the Riverbend Nuclear Generating Station. Hence, demand centers for the future potential demand for hydrogen from this plant are common. The largest hydrogen demand centers for ammonia production within 100 miles of Waterford NPP are:

- CF Industries in Donaldsonville, Louisiana, and Eurochem in Edgard, with 1868 and 430 MT/day, respectively
- Refineries such as Marathon Petroleum Corp in Garyville, Motiva Enterprises, LLC in Convent and Norco, and Valero Energy Corp in Norco with 535, 242, 240, and 229 tonnes/day, respectively, can also contribute to the hydrogen demand.

The potential demand for industrial heat from a nearby Dow chemical plant will be estimated and reported in future work. These demands contribute to more than half of the total potential demand for hydrogen within the 100-miles radius of the Waterford NPP.

3.1.2 Riverbend Nuclear Power Plant

The Riverbend Station (shown in Figure 10) is an NPP with a rated capacity 974 MWe—the potential to produce close to 600 tonnes/day of hydrogen—located in Louisiana. It is a sixth-generation General Electric BWR, with a thermal capacity of 3091 MW. It generates about 7–9 TWh/yr.

Figure 10. River Bend Station, Unit 1.

Total future potential demand of hydrogen from facilities within 100 miles of Riverbend NPP is 5511 MT/day. A more-detailed distribution of facilities that may demand hydrogen from this NPP is shown in Figure 11 and Figure 12. Ammonia production is the largest consumer of hydrogen, followed by refineries. Note that for this NPP, more than half of the total hydrogen demand centers are located beyond 50 miles.

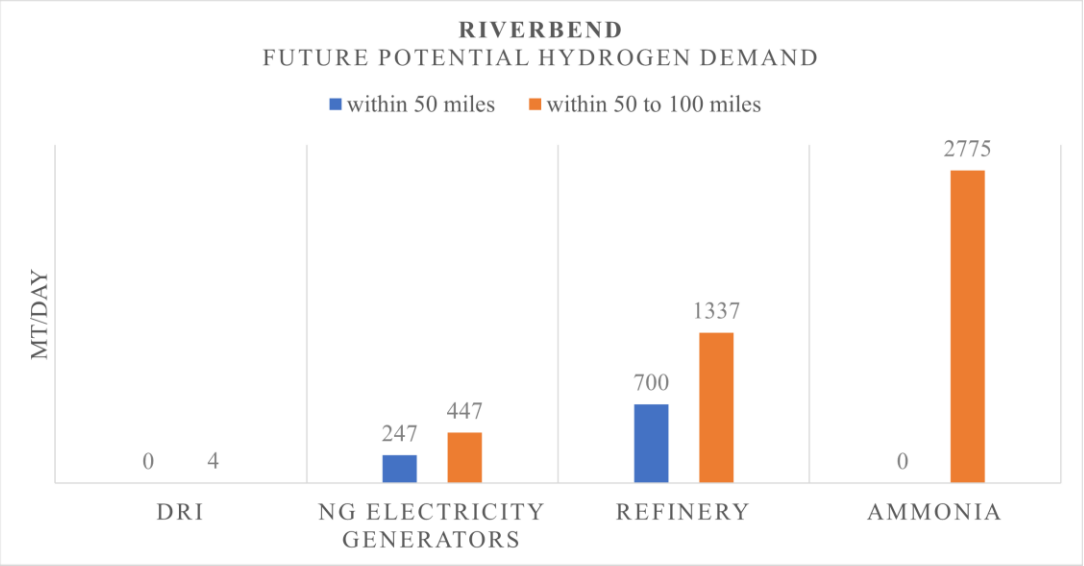
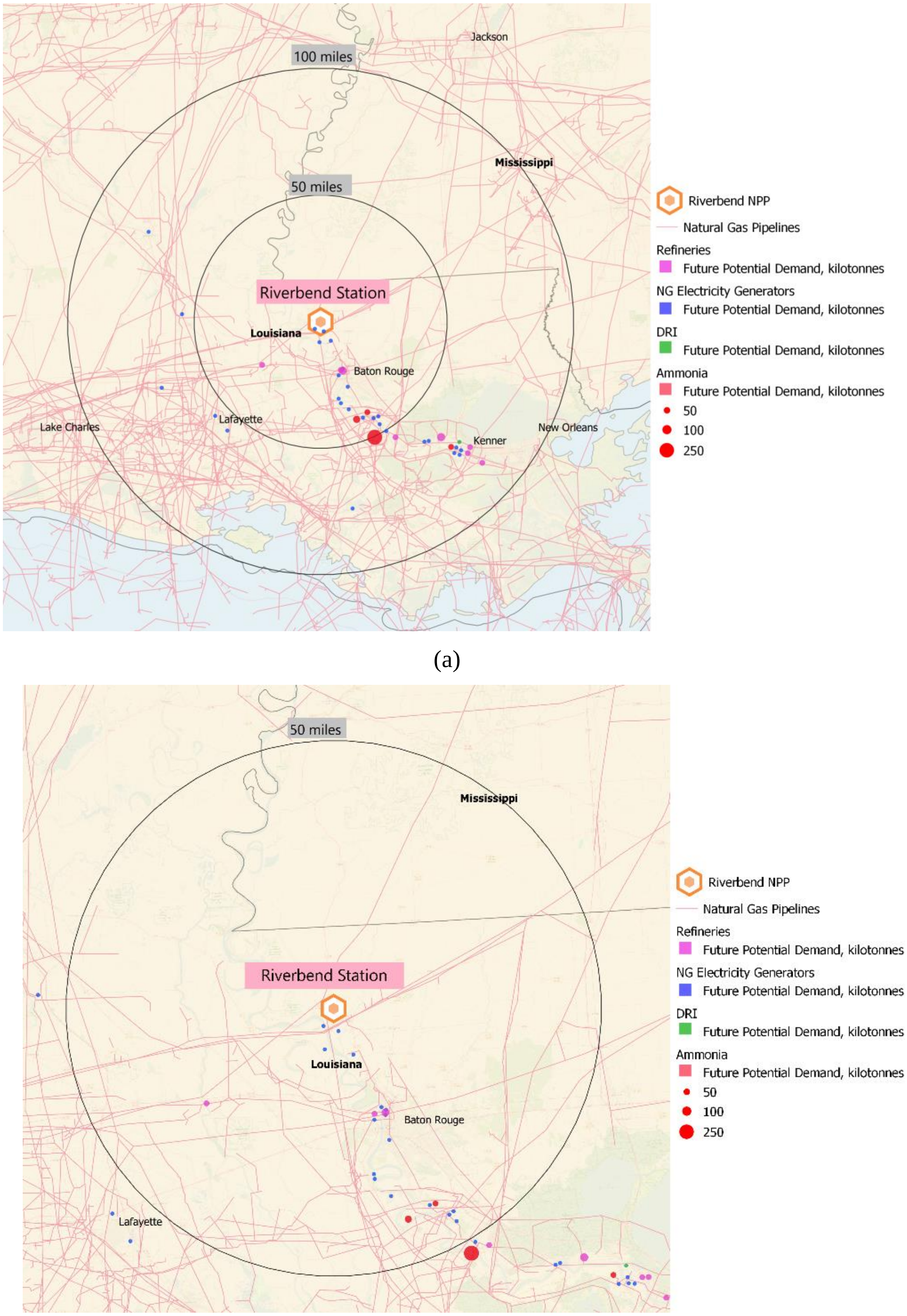


Figure 11. Distribution of future potential demand for hydrogen in the neighborhood of Riverbend NPP.



(a)

(b)

Figure 12. Centers for hydrogen demand for Riverbend NPP within (a) 100 and (b) 50 miles.

The Riverbend Station is located close to the Waterford 3 Nuclear Generating Station. Hence, demand centers for the future potential demand for hydrogen from this plant are common. The largest hydrogen demand centers within 100 miles of the Riverbend Station for ammonia production are:

- CF Industries in Donaldsonville and Eurochem in Edgard with 1868 and 430 MT/day, respectively
- Refineries such as ExxonMobil Corp in Baton Rouge and Marathon Petroleum Corp in Garyville with 535 and 578 MT/day, respectively.

These demands contribute to more than half of the total demand potential demand for hydrogen within the 100-miles radius of the Riverbend NPP.

3.1.3 Grand Gulf Nuclear Power Plant

The Grand Gulf Nuclear Station, located in Mississippi (and shown in Figure 13), is an NPP with a rated capacity of 1443 MWe—a potential to produce close to 900 tonnes/day. It is a BWR with a thermal capacity of 4408 MW. It generates about 7–12 TWh per year.

The future potential demand for hydrogen produced by this plant from facilities within 100 miles is 412 MT per day. A more-detailed distribution of facilities that may demand hydrogen from this NPP is shown in Figure 14 and Figure 15. Ammonia production is the largest consumer of hydrogen, followed by refineries. It may be noted that for this NPP, more than 50% of the total hydrogen demand centers are located beyond 50 miles.

Within the 100-miles radius of Grand Gulf Nuclear Station, the largest hydrogen demand arises from diverse potential applications:

- CF Industries in Yazoo City could require 249 MT/day of ammonia for production
- Ergon Biofuels, LLC, located in Vicksburg, Mississippi, may have a potential daily demand of 55 metric tons of syngas to produce ethanol
- Hinds Energy Facility in Vicksburg, Mississippi (owned by Entergy MS and Ergon) could require up to 73 metric tons of hydrogen per day for both its natural gas-fired electricity generation and refinery operations.

These demands contribute to more than 90% of the total demand potential demand for hydrogen from this NPP.

Figure 13. Grand Gulf Nuclear Station, Unit 1.

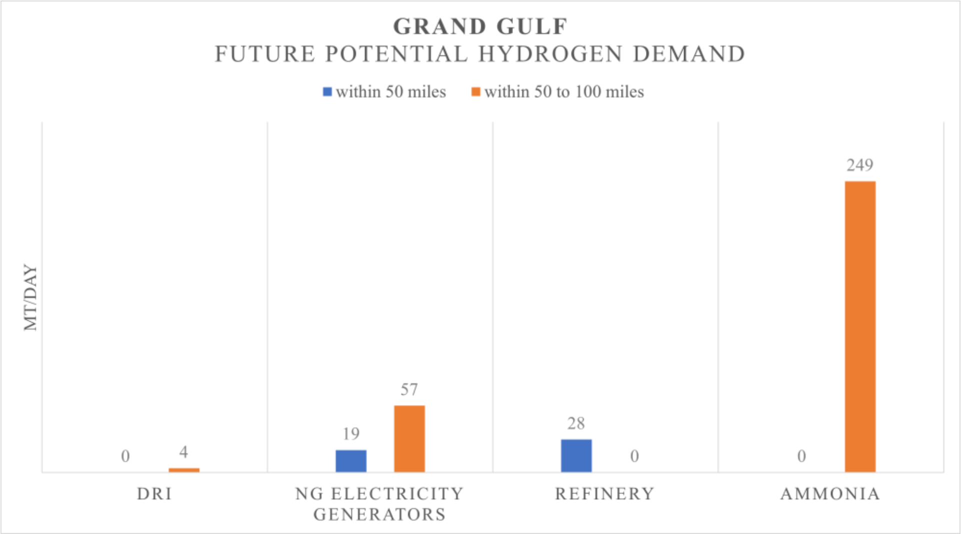


Figure 14. Distribution of future potential demand for hydrogen in the neighborhood of Grand Gulf NPP.

(a)

(b)

Figure 15. Centers for hydrogen demand for Grand Gulf NPP within (a) a 100 and and (b) 50 mile radius.

3.2 Potential Hydrogen Demand for Individual South Texas Nuclear Power Plants

The South Texas NPP, located close to Houston (and shown in Figure 16), has two reactors with a total rated capacity of 2646 MWe—the potential to produce more than 1800 tonnes/day). Both reactors are of PWR type, with a total thermal capacity of 7706 MW.

The potential demand for hydrogen from this plant from facilities within 100 miles is 2807 MT/day. More detailed distribution of facilities that may demand hydrogen from this NPP is shown in Figure 17 and Figure 18. Petroleum refineries represent the largest consumers of hydrogen, followed by e-fuel production.

Hif Global has a proposed e-methanol facility planned within 2 miles of STP and would have potential hydrogen demand of about 800 tonnes/day. This plant is planned for construction to start in 2024 is notable from a hydrogen, steam, and behind-the-meter electrical perspective.

Figure 16. South Texas NPP.

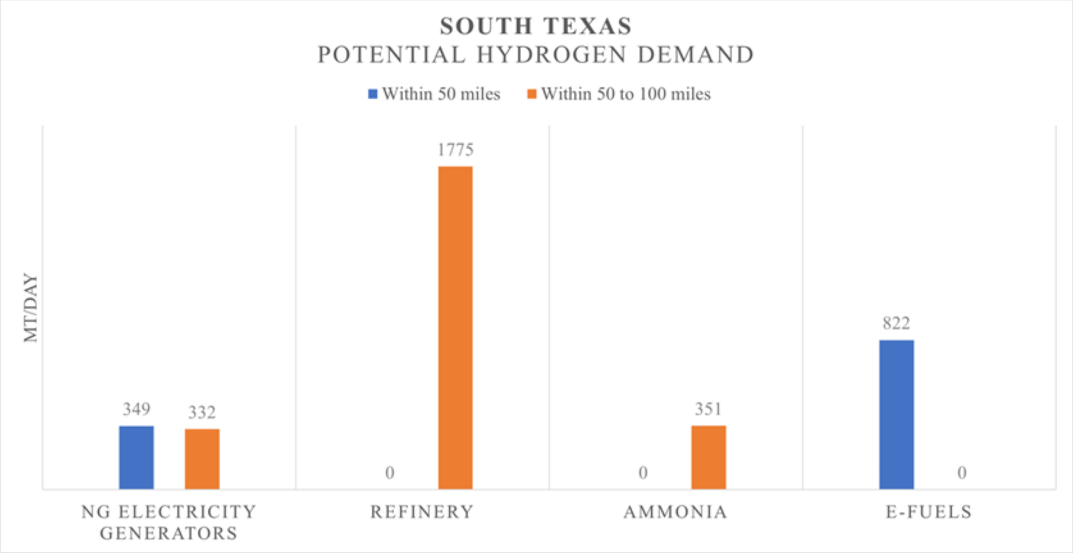


Figure 17. Distribution of potential demand for hydrogen in the neighborhood of South Texas NPP.

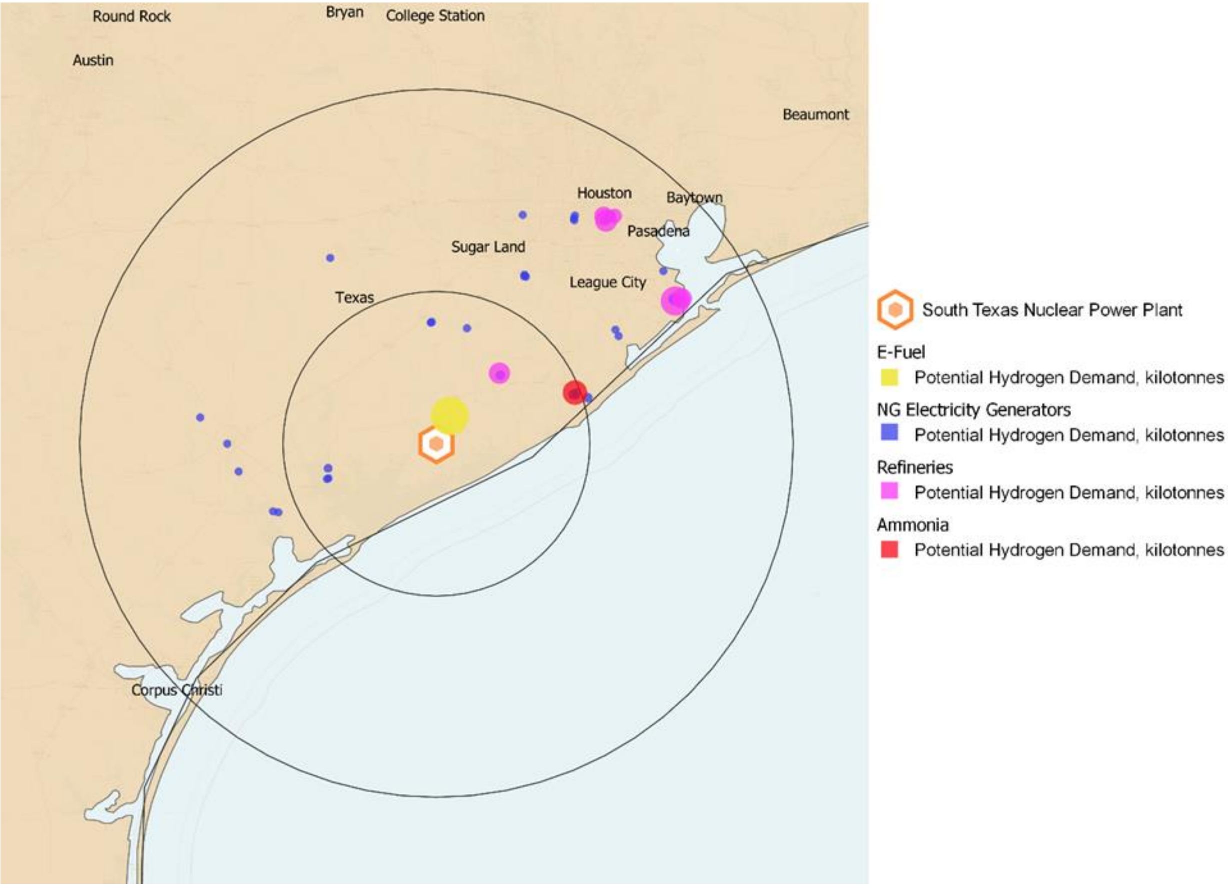


Figure 18. Centers for hydrogen demand for South Texas NPP within 50 and 100 miles.

3.3 Potential Hydrogen Demand for Individual Comanche Peak Nuclear Power Plant

The Comanche Peak NPP, located close to Dallas (and shown in Figure 19), has two reactors, with a total rated capacity of 2509 MWe—the potential to produce about 1700 tonnes/day). Both reactors are of PWR type, with a total thermal capacity of 7224 MW.

Figure 20 and Figure 21 provide insight into the potential demand for hydrogen within 100 miles of this NPP. Total potential demand is 332 tonnes/day, and electricity generation using natural gas is the largest consumer of hydrogen, followed by e-fuel production. The e-fuel facility is located at Hereford, within 50–100 miles.

Figure 19. Comanche Peak NPP.

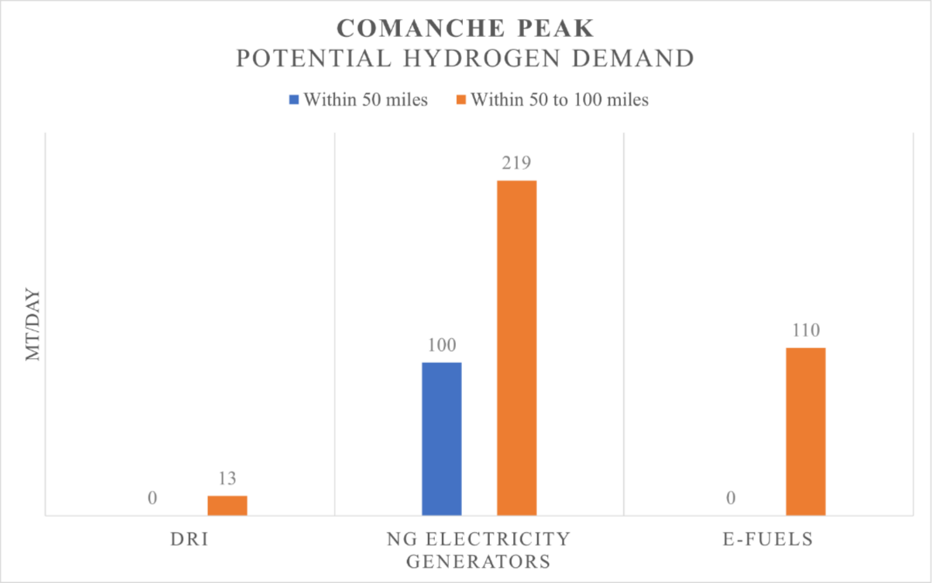


Figure 20. Distribution of potential demand for hydrogen in the neighborhood of Comanche Peak NPP.

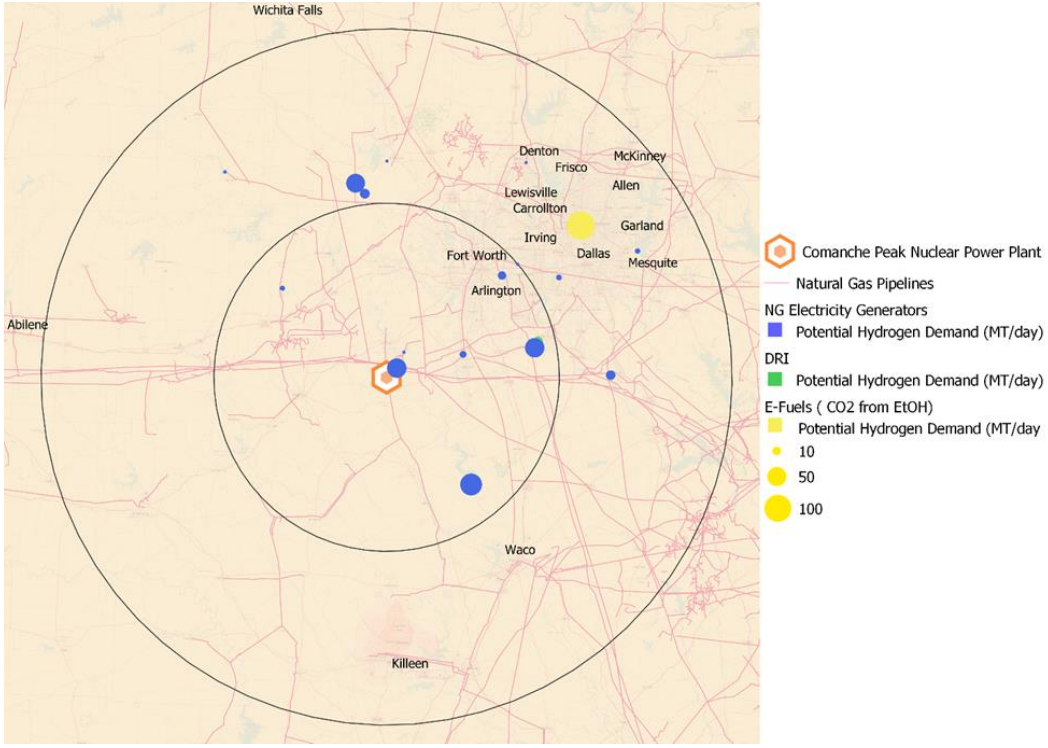


Figure 21. Centers for hydrogen demand for Comanche Peak NPP within 100 and 50 miles.

4. PRODUCTION TAX CREDITS

The IRA became law on August 16, 2022, facilitating federal investment in clean energy by introducing tax incentives for clean energy production and investment [18]. These tax credits are technology neutral, given that they acknowledge all energy technologies' vital role in meeting GHG emission-reduction targets. Nuclear energy and advanced nuclear energy are qualified for different tax credits. There is a PTC for existing NPPs, PTC Section 45U, and ITC 48E for advanced nuclear facilities. The tax credits also consider NPPs looking to uprate their existing facilities, as detailed in [19].

Also, the IRA provides tax credits for clean hydrogen produced from low-carbon pathways. In particular, the production of hydrogen with electrolysis from nuclear power is especially clean and will acquire the maximum tax credits. The Clean Hydrogen PTC (Section 45V), which is currently in force, introduces a new 10-year tax-support mechanism to promote clean-hydrogen production, offering a credit of up to \$3.00/kg-H_2 produced, depending on the intensity of CO_2 emitted in the hydrogen-production pathway. In other words, the credit amount is determined based on carbon intensity, with a maximum limit of 4 kg CO_2-equivalent/kg-H_2. It has been previously determined that existing U.S. NPPs should be able to qualify for the full \$3.00/kg-H_2 credit based on carbon intensity [20]. Emissions are measured up to the production point using the Argonne National Laboratory Greenhouse Gases, Regulated Emissions, and Energy use in Technologies (GREET) Model. [21]

Also, the Internal Revenue Service (IRS) established that the credit cannot be combined with the Carbon Capture and Sequestration Tax Credit (Section 45Q), but it did, in a notice from December 26, 2023, discuss whether PTC (45V) could be stacked with the renewable energy PTC (Section 45Y) or zero-emission nuclear credit (Section 45U). The IRS is considering a 10% allowance of the NPP electricity that could become energy-attribute certificates (EACs) for 45V credits. The 10% allowance is a side alternative that the IRS may consider based on forthcoming comments [22]. The proposal would entirely negate the 45-V EAC values to existing nuclear, while the two side alternatives would leave only 5 or 10% of the values calculated in the present report.

Finally, projects that adhere to prevailing wage standards and apprenticeship requirements can receive the full credit, as shown in Table 4 for the 45V.

Table 4 provides an overview and summary of the relevant tax credits for hydrogen production/cogeneration and NPPs. Subsequent sections will discuss the integration of hydrogen co-production with nuclear energy.

Table 4. Summary of IRA PTC and ITC tax credits. [25]

Tax Credit	Type: PTC or ITC	Amount	Term	Restrictions
Section 45U—Zero-Emission Nuclear Production Credit for Existing Reactors	PTC	Base: $3/MWh Total credit: $15/MWH (with 5× multiplier)	10 yrs. Electricity produced and sold after December 31, 2023, and before December 31, 2033	Based on gross receipts and prorated 100% at gross receipts at [$0/MWh-$25/MWh] 0% when gross receipts exceed $43.75/MWh
Section 45Y—Electricity Production Credit (PTC for New Facilities)	PTC	$25/MWh Base L-1.1 +10% for energy community. +10% for domestic Total credit: $30/MWh	10 yr or annual U.S. GHG emissions from electricity production is equal or less than 25% of GHG emissions in 2022	Zero GHG electricity generation facility Take only 45Y or 45E Placed ln service after December 31, 2024
Section 45E—Clean Electricity Investment Credit (for New Facilities)	ITC	30% of investment - Base +10% points for “energy community.” +10% points for domestic Total credit: 50% of investment	10 yr or annual U.S. GHG emissions from electricity production is equal or less than 25% of GHG emissions in 2022	Zero GHG electricity generation facility Take only 45Y or 45E Placed in service after December 31, 2024
Section 45V—Clean Hydrogen Production Credit	PTC	Base: $0.60/kg of H_2 $3.00/kg of H_2 with 5× multiplier for wage details	First 10 yr after a facility is placed in service. Available after January 1, 2023	Pathway GHG emissions must be less than 4 kg of CO/kg of H_2 Prorated based on pathway emissions Owned by taxpayers

The Department of Treasury and the IRS are still establishing and defining the rules and application details of the tax credits. As a result, IRA tax-incentive information contained in this report could change and should be considered as the best estimate at this time. [19]

4.1 Clean-Hydrogen Production Credit (Section 45V)

A tax incentive for clean-hydrogen production is available through Section 45V of the Internal Revenue Code, effective January 1, 2023. This section offers a tax credit for qualified clean-hydrogen production facilities that are owned by the taxpayer, produce qualified clean hydrogen, and begin construction before January 1, 2033. The credit applies for the first 10 years of operation after the hydrogen-production facility is placed in service.

To qualify, clean hydrogen must be produced in the U.S. as part of the taxpayer's regular business activities and meet additional requirements set by the Treasury Secretary. The hydrogen must also be sold to or used by an unrelated third party. The value of the PTC depends on the life-cycle GHG emissions from the facility's hydrogen-production process. Processes with lower GHG emissions qualify for higher tax credit values. To be considered clean hydrogen, the production process must emit no more than 4 kg CO_2e/kg-H_2. If the prevailing wage and apprenticeship requirements outlined in the IRA are met, the base tax credit is increased fivefold. For processes with GHG emissions below the 4 kg CO_2e/kg-H_2 threshold, portions of the tax credit are detailed in Table 5. Nuclear-integrated hydrogen production meets the GHG-emissions criteria to qualify for the maximum hydrogen PTC.

Table 5. Hydrogen PTC tiers by life-cycle GHG emissions.

Life-Cycle GHG Emissions (kg CO_2e/kg H_2)	PTC (% of base rate)
Less than 0.45	100%
0.45–1.5	33.4%
1.5–2.5	25%
2.5–4	20%

The hydrogen-pathway GHGs, respective base tax credits, and tax credits with the wage and apprenticeship multipliers are summarized in Table 6.

Table 6. Tax credits based on life-cycle GHG emissions of hydrogen pathways.

CO_2 Emission Rate	Percentage of Base Tax Credit	Resultant Base Tax Credit (per kg-H_2)	Resultant Tax Credit with 5× Multiplier (per kg-H_2)
Greater than 4 kilograms of CO_2e per kilogram of hydrogen	0%	0	0
Not greater than 4 kilograms of CO_2e per kilogram of hydrogen, and not less than 2.5 kilograms of CO_2e per kilogram of hydrogen	20%	$0.12	$0.60
Less than 2.5 kilograms of CO_2e per kilogram of hydrogen, and not less than 1.5 kilograms of CO_2e per kilogram of hydrogen	25%	$0.15	$0.75
Less than 1.5 kilograms of CO_2e per kilogram of hydrogen, and greater than 0.45 kilograms of CO_2e per kilogram of hydrogen	33.4%	$0.20	$1.00
Less than 0.45 kilograms of CO_2e per kilogram of hydrogen	100%	$0.60	$3.00

According to the Argonne National Laboratory GREET Model, the life-cycle GHG emissions from hydrogen produced through HTSE and LTE integrated with nuclear energy are less than 0.45 kg $CO_2e/kg-H_2$, qualifying for the full Section 45V tax credit. As illustrated in Figure 22, the life-cycle emissions for hydrogen production via LTE using nuclear-based electricity are approximately 0.4 kg $CO_2/kg-H_2$. For hydrogen produced via HTSE with nuclear-based electricity, the life-cycle emissions are around 0.3 kg $CO_2/kg-H_2$. [23]

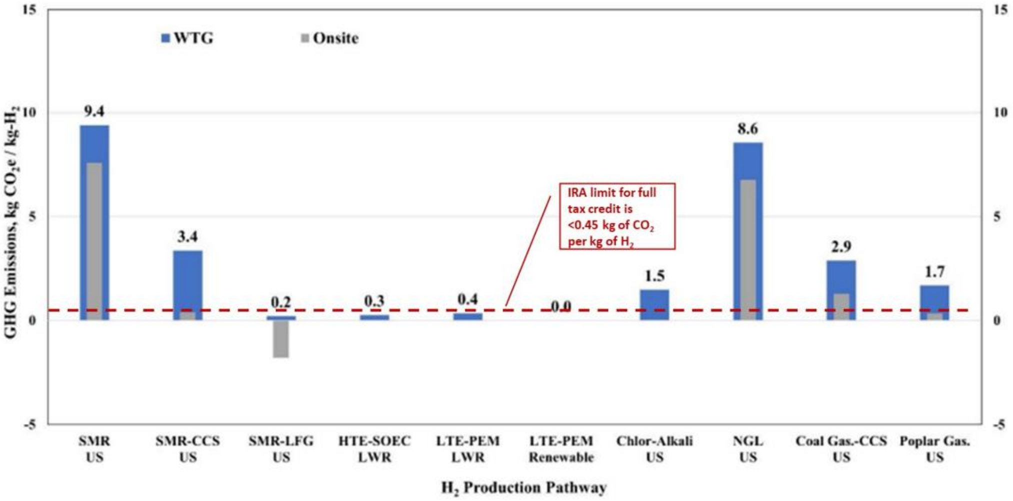


Figure 22. Life-cycle GHG emissions from LTE and HTSE electrolysis with nuclear energy. [23]

Consequently, these hydrogen-production pathways qualify for the full base tax credit of $0.60/kg-$H_2$ and the enhanced tax credit of $3.00/kg-$H_2$ when the multiplier is applied. Section 45V specifies that life-cycle GHG emissions “only include emissions through the point of production (well-to-gate),” as determined using the most recent “Greenhouse GREET model” developed by Argonne National Laboratory. Therefore, it is essential to determine the life-cycle GHG emissions of the hydrogen-production process, including the evaluation of the electricity used, whether it is sourced from the grid or behind-the-meter. The last guidance on these issues can be seen in [24].

Figure 23 shows the PTC 45V rate according to the kilograms of CO_2 emitted by kilogram of hydrogen produced.

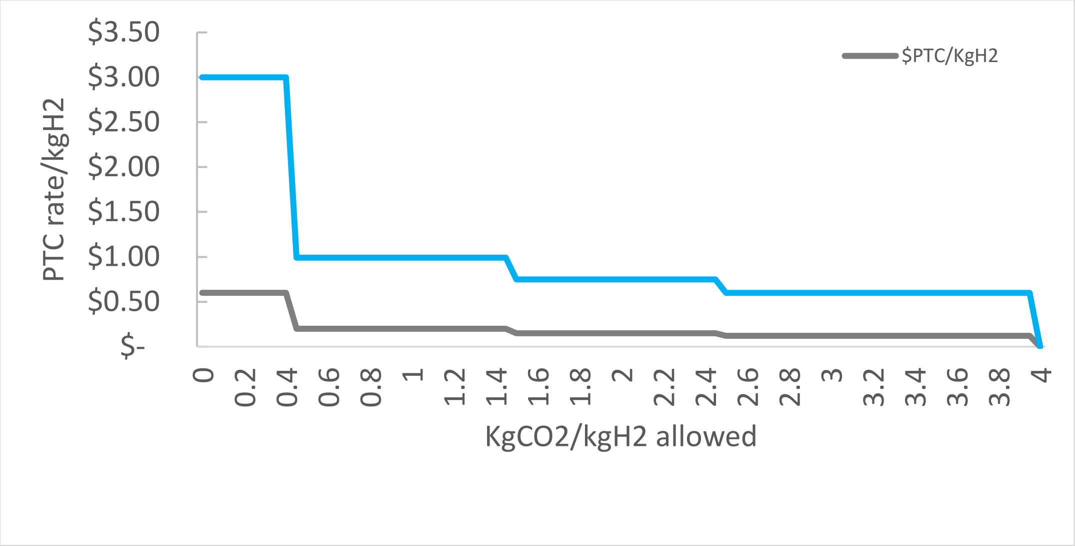


Figure 23 .PTC rate for 45V.

Also, in the IRS draft rule from last December, the IRS is evaluating whether, under Section 45U, existing nuclear plants are eligible to receive credits both for electricity under Section 45U and for hydrogen production under Section 45V if their electricity is used for a clean hydrogen-production facility at a qualified nuclear facility. The IRS is also considering feedback from companies and individuals to determine whether existing nuclear plants might be eligible for credits under both Section 45Y (for additional-capacity electricity production) and Section 45V.

Note also that similar to Sections 45Y and 45E, the Section 45V tax credit includes provisions that reduce the credit if tax-exempt bonds are used to finance the facility. The credit reduction is the lesser of either 15% or the fraction of the proceeds from the tax-exempt bond used for financing the facility over the total additions to the capital account for the qualified facility [24].

It is important to note that hydrogen production is highly energy-intensive, and under IRA targets, the tax credits received by a hydrogen facility will depend on the emissions generated upstream of the hydrogen production facility. Assessing and accounting for the GHG emissions of hydrogen production facilities is not an easy task, particularly when the hydrogen plant is located in a different part of the power grid from the renewable power plant supplying its energy. The following subsections will address some of these issues.

4.1.1 “Additionality” Question

The issue of additionality arises from the concern that, given a fixed supply of clean electricity in an area (such as from nuclear sources), adding a hydrogen production facility that draws on this existing clean energy from the grid could lead to an increase in emissions. This is because the grid might need to compensate for the diverted clean energy by using peaker plants, such as natural gas plants. This question remains unresolved at the time of this report. Without adding new renewable energy sources to the area concurrently, the replacement electrical power may initially have to come from carbon-emitting sources until new clean generation is built out.

Under these conditions, the replacement grid power needs are likely to be met by fossil fuel sources, which often have unused zero marginal cost capacity that can be easily ramped up compared to renewable sources, which generally produce as much as they can.

The overall concern is that the net downstream effect of using existing clean energy sources for hydrogen production could lead to more carbon emissions if the resulting deficit in grid power is not compensated by adding other clean energy sources. In other words, increasing hydrogen production raises energy demand, which should be considered when measuring the impact on the proportional carbon footprint of the electrical grid.

4.1.2 Regionality Mismatch

It is also crucial to consider the location of new renewable sources, even if additionality issues are addressed and new renewable sources are built. For example, if new renewable power plants are constructed in a state with a highly carbon-intensive energy grid, these cleaner sources will replace the more carbon-intensive sources. However, if a hydrogen-production facility is built in a state with a high-carbon grid while the renewable power plants are built in a greener state, the net effect of emissions could be higher. This is because the hydrogen plant would be drawing its electricity from a carbon-intensive grid. Therefore, it is necessary to ensure that there is some matching of electricity supply and demand within the same area.

4.1.3 Monetizing the Clean-Hydrogen-Production Credit (Section 45V)

Under Section 6417 of the Internal Revenue Code, part of the IRA, “applicable entities” that do not owe federal income tax can still receive tax credits through an elective-payment mechanism. This option allows these entities to receive clean-energy tax credits even without federal income tax liability.

These entities can elect to treat a specified applicable tax credit as a payment against the tax imposed by Subtitle A of the Internal Revenue Code for the corresponding taxable year [26]. If this option is chosen, the tax credit amount is considered a payment of tax, potentially resulting in a refund for any overpayment [26].

Eligible credits for this election include the Energy Credit (Section 48), Clean Electricity Investment Credit (Section 48E), Renewable Electricity Production Credit (Section 45), and Clean Hydrogen Production Credit (Section 45V). However, eligibility for elective pay depends on meeting specific requirements for each tax credit. Some credits have date restrictions and specific eligibility criteria that must be met to receive the credit. [25]

Taxpayers who are not applicable entities can choose the elective pay option only for the Section 45V Credit for Production of Clean Hydrogen, Section 45Q Credit for Carbon Oxide Sequestration, or Section 45X Advanced Manufacturing Production Credit. [27]

4.2 Zero Emission Nuclear Power Credit (Section 45U)

IRA Section 45U, Zero Emission Nuclear Power Credit, is a tax credit for electricity produced at qualified nuclear-power facilities, specifically targeting existing NPPs that were not eligible for the 45J credit at the time of the IRA’s enactment. It is important to note that under Section 45U, the PTC rate is reduced based on the company’s gross receipts. The PTC is reduced when the taxpayer’s gross receipts exceed $25/MWh, as shown in [28]. The maximum gross receipts that can receive the tax credit are $43.75/MWh; beyond this amount, no tax credits are allowed. [29]

Table 7. Maximum credit rate from the IRA PTC Section 45U.

	PTC Adjustment Formula	Gross Receipts Requirement
PTC $/MWh	3	if $0 < GR \leq 25$
PTC $/MWh	$3 - 1.67 \times (GR - 25)$	if $0 < GR \leq 43.75$
PTC $/MWh	0	if $GR > 43.75$

Also, payments from federal, state, or local zero-emission nuclear subsidies reduce the credit amount, and there is no energy community bonus associated with this credit. Direct-pay eligibility applies to tax-exempt organizations, states, political subdivisions, the Tennessee Valley Authority, Indian Tribal governments, Alaska Native Corporations, and rural electricity co-ops. This credit is transferable, but not stackable with the 45J advanced-nuclear PTCs. [30]

Figure 24 shows the 45U rates with and without labor requirements as a function of the gross receipts.

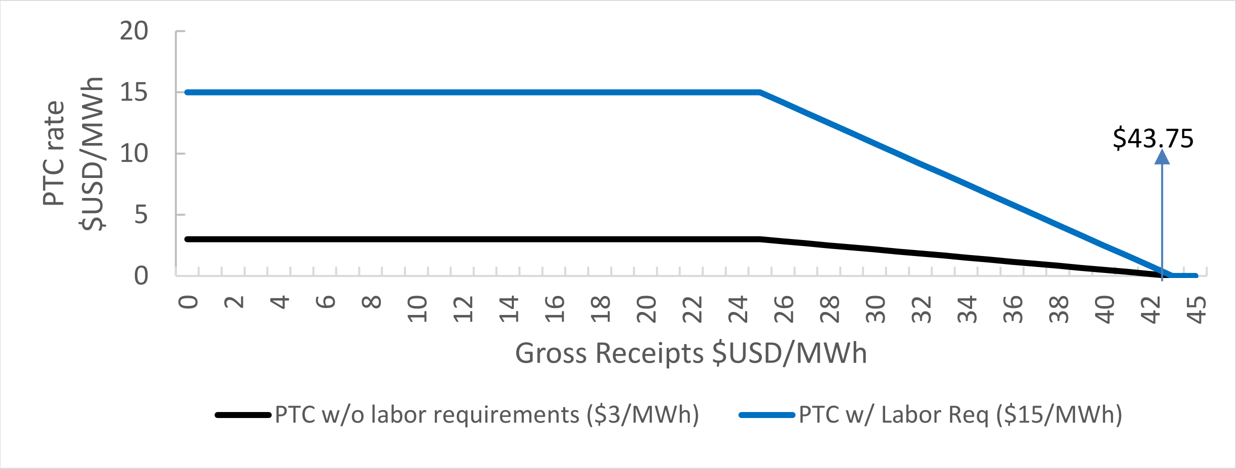


Figure 24. Section 45U PTC rates with and without labor requirements.

In Table 6, the potential tax credits available for hydrogen production plants and NPPs are listed. A detailed description can be found in the corresponding section in this report. For each scenario created, the tax credits assumed available will be explicitly called out. For all analysis in this report it is assumed that nuclear integrated hydrogen production can take advantage of the full $3/kg PTC under 45V.

5. NUCLEAR INTEGRATED HYDROGEN PRODUCTION ANALYSIS

The TEA performed in this report is based on the NIHPA tool [6] developed at INL. The NIHPA tool has been verified against the NREL H2A model [4] and the default values were adopted from a 2023 hydrogen-market report [31]. The NIHPA tool uses cash-flow analysis to estimate the financial performance including LCOH, internal rate of return (IRR) for hydrogen production, net present value (NPV) of cashflows in hydrogen production, NPV of business-as-usual (BAU) case (where the electricity required to produce hydrogen is assumed to be sold to the grid), and the difference between NPV of cashflows in hydrogen production and the BAU case (delta NPV).

The NIHPA tool was originally designed to analyze nuclear-integrated hydrogen production with a PWR coupled with HTSE. HTSE requires inputs of both electricity and thermal power. For this project, LTE was integrated into the NIHPA tool. LTE does not require thermal energy, but uses a larger amount of electricity to produce hydrogen at lower production efficiency. Also, the capability to analyze a BWR was added.

Key foundational inputs to the NIHPA tool originated from a preconceptual design for the development and integration of a 500MW_{nom} HTSE hydrogen production facility with a representative, generic LWR 1200 MWe NPP. The steam extraction from an NPP connecting with an HTSE system is graphically represented by Figure 25 while the electricity power modification required is shown in Figure 26. In Figure 25, the LTE connecting to the electricity outputs from an NPP is also included and compared to HTSE.

The LCOH with and without hydrogen PTC were compared. Sensitivity studies were performed with respect to LCOH without PTC and NPV of cashflows for hydrogen production to identify underlying contributing factors. Profitability analysis was performed to identify the profitable conditions for hydrogen production. Preference analysis was done by comparing the NPV of cashflows of hydrogen production to the BAU case of 100% of NPP production of electricity to the grid. Competitive analysis was executed to compare the LCOH between nuclear-integrated hydrogen production and the hydrogen produced using SMR.

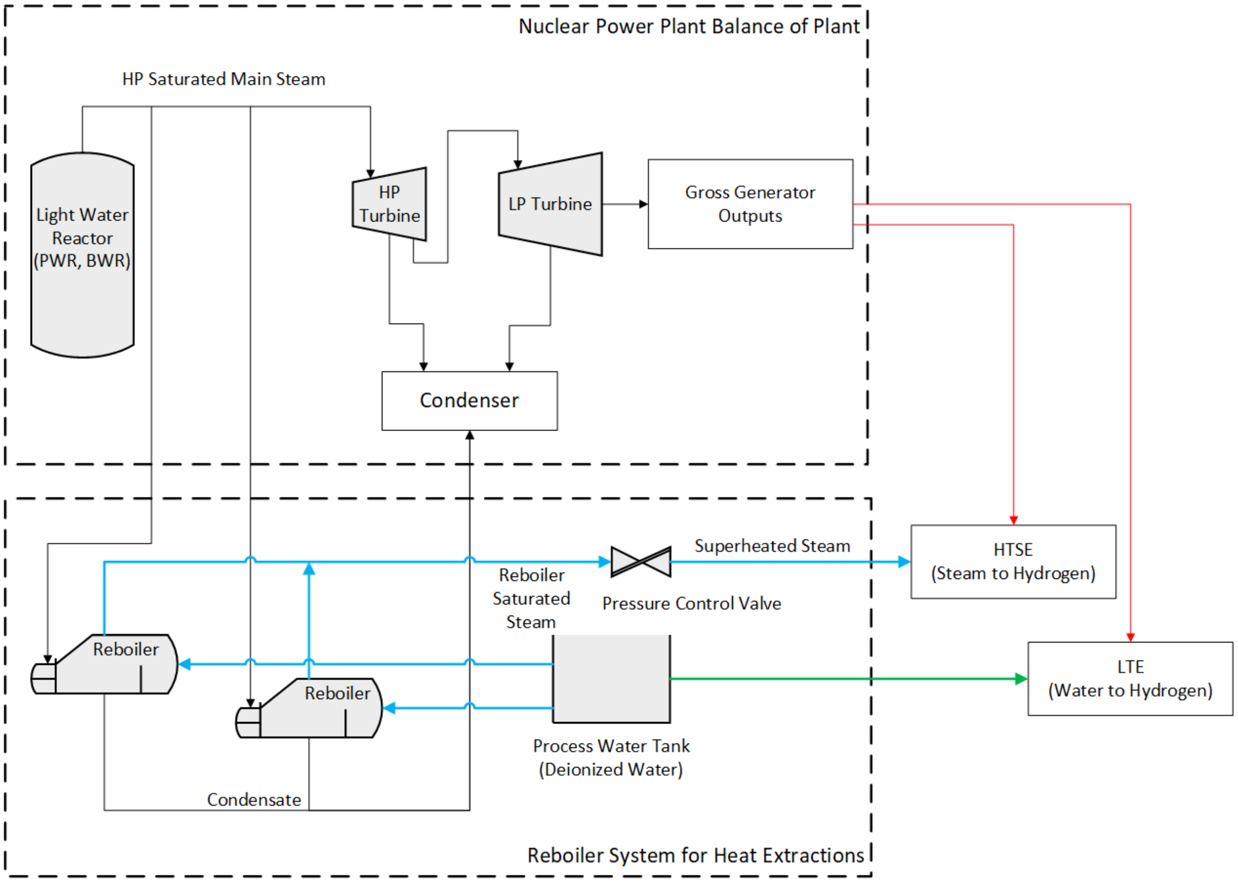
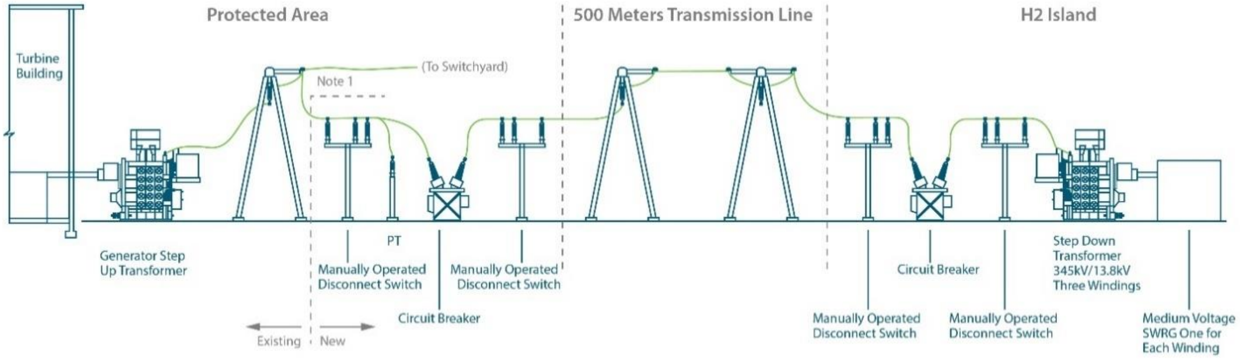


Figure 25. Process flow diagram for nuclear-integrated hydrogen production via either HTSE or LTE. The blue arrow represents the process steam flow for HTSE while green arrow represents the process water flow for LTE. The red arrow represents the electricity requirement for both HTSE and LTE.



Note:
1. Connection Located Behind the Meter.

Figure 26. Electrical power modification for connecting hydrogen production facilities.

5.1 Assumptions

The original version of the NIHPA tool used default values applicable to Xcel Energy's Prairie Island and Monticello nuclear generating stations per a previous public report [2]. Based on different characteristics of the problems in the Gulf Coast and the most-recent analysis [5], the following changes were made:

- Applied the same assumptions for both PWR and BWR plants (Section 5.1.1)
- Included the cost of hydrogen production from LTE to be compared with HTSE (Section 5.1.2)
- Updated the costs of hydrogen production from HTSE
    - Ensured the stack cost for HTSE includes a contingency of 10% and stack cost markup is 30%
    - Updated rectifier capital-cost value
    - Did not apply the learning-curve cost reductions to the indirect cost input specification
- Included the hydrogen transportation costs (Section 5.1.3).

5.1.1 PWR and BWR Plants

The market analysis presented the hydrogen demands around four NPPs owned by Entergy, two NPPs owned by the South Texas Project, and two NPPs owned by Comanche Peak. The Waterford 3, Arkansas NPP, South Texas 1 and 2, and Comanche Peak 1 and 2 are PWR designs while Riverbend and Grand Gulf NPPs are BWR designs. One major difference between PWRs and BWRs is related to steam generation. In a PWR, a steam generator is treated as a heat exchanger to convert the heat from the isolated primary loop to produce steam in the secondary loop. However, in a BWR plant, a steam separator connected to the reactor is used to separate the liquid phase and the vapor phase of the water directly, instead of using the steam generator. Due to the different configurations and the way that the steam is generated, different integration costs can be applied for PWR and BWR plants. In this analysis, it is assumed that both PWR and BWR can connect to HTSE with similar reboiler heat-exchanger configurations, as represented in Figure 25, with the primary exception that, for a BWR, a second set of reboilers would be provided in series between the NPP and HTSE to assure containment of radioactive contaminants within the site boundary. For simplicity, only the five PWR design in the Gulf Coast: Waterford 3, South Texas 1 and 2, and Comanche Peak 1 and 2 are compared in this report.

5.1.2 HTSE and LTE Comparisons

For the comparison of HTSE and LTE hydrogen-production options, the following additions were made to the NIHPA tool:

- Incorporated hydrogen-production rate for LTE
- Incorporated scaling factor for DCC estimations for LTE
- Incorporated time-dependent degradation rates for stacks
- Set the coolant-water usage and thermal-energy usage equivalent to zero for LTE
- Included the process-water usage for LTE
- Included the power conversion from AC to DC for LTE
- Included the electrical-power requirement for LTE
- Included the stack costs for LTE.

Table 8 compares the assumptions made for the HTSE and LTE systems. Note that Hydrogen and Fuel Cell Technology Office (HFTO) records were used for LTE, which did not provide some of the information, such as stack operating pressure, operating mode, stack-inlet water composition, sweep-gas inlet flow-rate utilization, and hydrogen-product purity.

Table 8. HTSE and LTE and related subsystem process operating condition specifications.

Parameter	HTSE		LTE	
	Value	Reference or Note	Value	Reference or Note
Stack operating temperature	800°C	[32]	80°C	[33]
Stack operating pressure	5 bar	See [3]	–	
Operating mode	Constant current		–	
Initial cell voltage	1.29 V/cell	Thermoneutral stack operating point [3]	1.9 V/cell	[33]
Current density	1.5 A/cm²	[34]	2 A/cm^2	[33]
Stack inlet H_2O composition	90 mol%	[32]	–	
Steam utilization	80%	See INL/RPT-22-66117 Section 2.2.1 [3]	0%	
Modular block capacity	25 MW-dc	Estimates presented in this document require consideration of fractional modules (i.e., system capacities evaluated are <25 MW-dc)	0.793 MW-dc (Need 150 stacks to have 119 MW-dc)	[33]
Sweep gas	Air	[32]	Air	[33]

Parameter	HTSE		LTE	
	Value	Reference or Note	Value	Reference or Note
Sweep gas inlet flow-rate	Flow set to achieve 40 mol% O_2 in anode outlet stream		–	
Stack service life	5 years	The five years of the stack service life is proposed considering the current progress of electrolysis technologies	7 years	[33]
Stack degradation rate	First year: zero degradation Second year: 0.25%/1,000 hours Third year: 0.5%/1,000 hours Fourth year: 0.75%/1,000 hours Fifth year: 1%/1000 hour	The stack degradation rates are assumed based on the internal discussions	First year: zero degradation Second year: 0.08%/1,000 hours Third year: 0.16%/1,000 hours Fourth year: 0.24%/1,000 hours Fifth year: 0.32%/1000 hour Sixth year: 0.39%/1000 hour Seventh year: 0.47%/1000 hour	[33]
Stack replacement schedule	5 years.	Stacks are staggered in replacement schedule in each module so as to ensure continuous operation during stack replacement	All of stacks are replaced every seven years.	

Parameter	HTSE		LTE	
	Value	Reference or Note	Value	Reference or Note
H_2 Product Pressure	20 bar (290 psi)	[3]. Compression to this level is achieved as a result of product purification by successive compression and interstage cooling steps. Further compression for storage or transportation will be required and is not included in this analysis.	31 bar (450 psi)	[33]
Efficiency (HHV)	90%	[3]	78.2%	[33]
H_2 Product Purity	99.9 mol% H_2	Water condensation from cooling and compression only; no PSA/TSA steps included	–	

5.1.3 Piping Costs for Hydrogen Transportation

In this analysis, the hydrogen transportation and delivery costs are estimated using the Hydrogen Delivery Scenarios Analysis Model. Only the piping and compressor costs are included while the refueling and the hydrogen storage costs are excluded. The calculated costs of the delivery are directly added to the breakeven LCOH production, assuming that cost of hydrogen production and the costs of the delivery are independent. The financial parameters in estimating the costs of the hydrogen delivery are consistent with those in hydrogen production.

5.2 Case Descriptions

Two types of cases are used in this report for Waterford 3, Riverbend, and Grand Gulf, South Texas, and Comanche Peak NPPs, as shown in Figure 27.

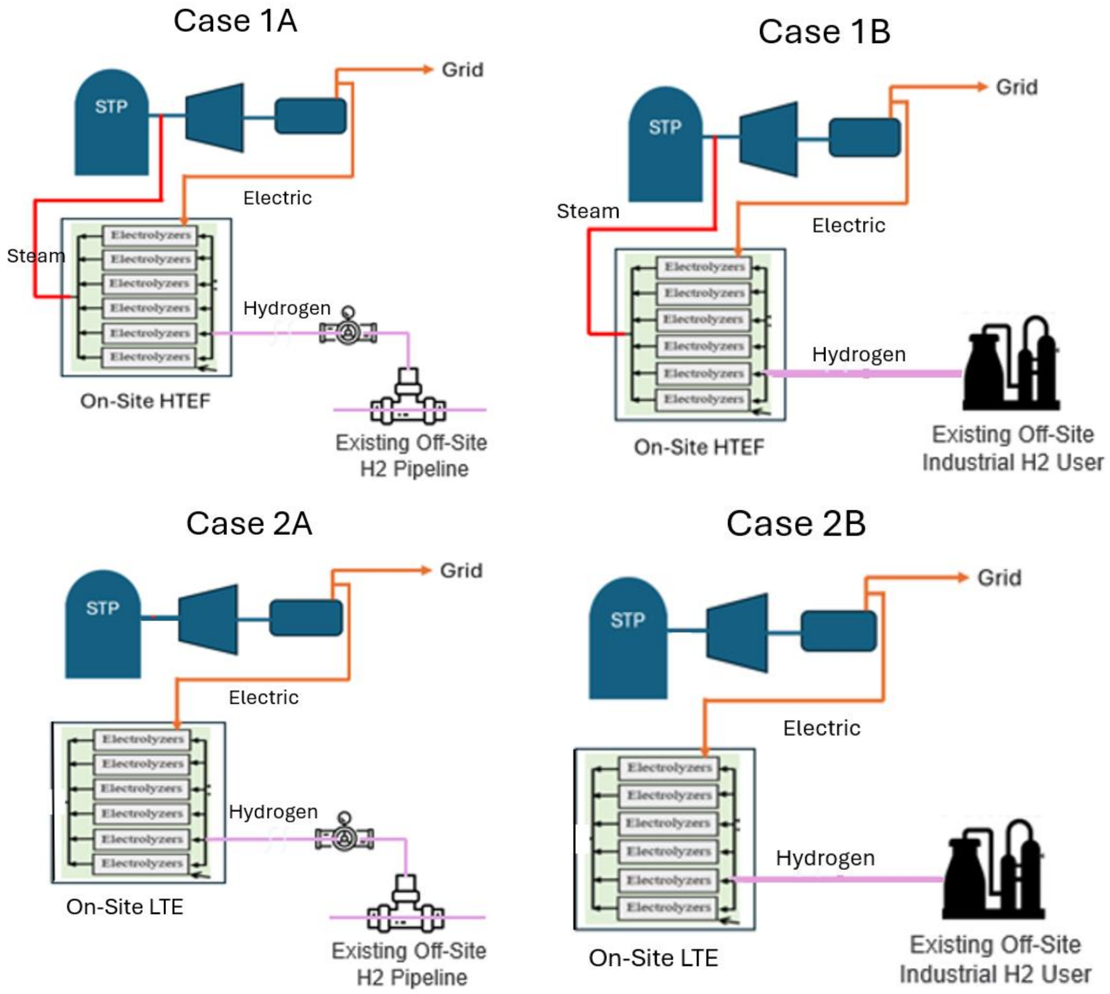


Figure 27. Case descriptions for Case 1A, Case 1B, Case 2A, and Case 2B.

The following case descriptions apply:

- Case 1A represents nuclear-integrated hydrogen production through HTSE to hydrogen pipeline network at 351 tonnes/day
- Case 1B represents nuclear-integrated hydrogen production through HTSE directly to an industrial user at 351 tonnes/day
- Case 2A represents nuclear-integrated hydrogen production through LTE to hydrogen pipeline network at 231 tonnes/day
- Case 2B represents nuclear-integrated hydrogen production through LTE directly to an industrial user at 231 tonnes/day

Note 1: *For Case 1A and Case 2A, the hydrogen will be delivered to the nearest pipeline based on the National Pipeline Mapping System*.

Note 2: *For Case 1B and 2B, the hydrogen will be transported to the nearest potential hydrogen demand*.

Table 9 documents the selected cases to perform TEA based on different market demand and the maximum hydrogen-supply capacity with 100% capacity factor. Electrolyzer sizes are calculated for the corresponding hydrogen-production rate. In the case where market demand is greater than the maximum hydrogen-supply capacity, only a portion of the hydrogen demand is assumed to be met. This is based on the current evaluated maximum electric and steam diversion design [10], which was evaluated by the research for implementation under licensee self-evaluation (without Nuclear Regulatory Commission [NRC] license-amendment request). As actual front-end engineering and design studies are completed by licensees, larger HTEF capacities may emerge as possible (with or without license-amendment requests). However, this is outside of the scope of the studies.

Table 9. Cases to run TEA for different demand types based on the closest pipeline and industrial users.

NPP	Case descriptions	Tier	Demand Type	Market Demand (MT/day)	Electrolyzer Size (MW-dc)	Maximum H_2 supply @100% capacity factor (MT/day)	Distance (km)
Waterford	Case 1A: Nearby Pipeline	1,2	General	351	500	351	0.3
	Case 2A: Nearby Pipeline	1,2	General	231	500	231	0.3
	Case 1B: Dyno Nobel	1	Ammonia	400	500	351	25.0
	Case 2B: Dyno Nobel	1	Ammonia	400	500	231	25.0
Riverbend	Case 1A: Nearby Pipeline	1,2	General	351	500	351	32.0
	Case 2A: Nearby Pipeline	1,2	General	351	500	231	32.0
	Case 1B: Exxon Mobil Corp	1	Refinery	535	500	351	39.7
	Case 2B: Exxon Mobil Corp	1	Refinery	535	500	231	39.7
Grand Gulf	Case 1A: Nearby Pipeline	1,2	General	351	500	351	169.8
	Case 2A: Nearby Pipeline	1,2	General	351	500	231	169.8
	Case 1B: Ergon Inc	1	Refinery	28.2	40	28.2	31.6
	Case 2B: Ergon Inc	1	Refinery	28.2	61	28.2	31.6
STP	Case 1A: Nearby Pipeline	1,2,3	General	351	500	351	40.6
	Case 2A: Nearby Pipeline	1,2,3	General	231	500	231	40.6
	Case 1B: HFI	3	Methanol	600	500	351	3.2
	Case 2B: HFI	3	Methanol	600	500	231	3.2
CP	Case 1A: Nearby Pipeline	2,3	General	351	500	351	431.2
	Case 2A: Nearby Pipeline	2,3	General	231	500	231	431.2
	Case 1B: Hereford Renewable	3	E-fuels	110	157	110	158.7
	Case 2B: Hereford Renewable	3	E-fuels	110	238	110	158.7

5.3 TEA Results and Analysis using NIHPA

5.3.1 Input Specification for Entergy, STP and CP plants

Leveraging the NIHPA tool, the following inputs are applied as noted in Table 10:

Table 10. Parameters for NPP plants that owned and operate the hydrogen-production facilities and delivery system.

Parameter	Value	Notes/Data source
Debt interest rate	5.23%	Ref. [35]
Equity interest rate	7.73%	Ref. [35]
Debt financing	51.83%	Ref. [35]
Equity financing	48.17%	Ref. [35]
Plant design	Nth-of-a-kind	95% learning rate; N=100 considering HTSE is not a new technology
Dollar year	2022	This is last year that Chemical Engineering Plant Cost Index (CEPCI) data are available
Start-up year	2030	It is assumed that we start constructing the HTSE facilities within 5 years
Federal Tax Rates	21%	Federal tax rate in U.S.
Capacity factor	93%	An averaged value of the existing U.S. NPPs [36]
Thermal efficiency	34%	The default value used in [3]
Waterford 3 NPP, Riverbend, and Grand Gulf owned by Entergy		
Electricity price	\$35/MWh	Fixed throughout entire plant life based on the private communication with the plant expert
State Tax	9.45%	This includes the country, city and state taxes based on [37]
WACC	5.66%	This is calculated based on WACC equation
South Texas 1 and South Texas 2 owned by STP		
Electricity price	\$31/MWh	Fixed throughout entire plant life based on the private communication with the plant expert
State Tax	6.25%	This includes the country, city and state taxes based on [38]
WACC	5.73%	This is calculated based on WACC equation
CP-1 and CP-2 owned by Comanche Peak		
Electricity price	\$20/MWh	Fixed throughout entire plant life based on the private communication with the plant expert
State Tax	8.25%	This includes the country, city and state taxes based on [39]
WACC	5.69%	This is calculated based on WACC equation

Some common critical inputs used in HTSE and LTE are compared in Table 11.

Table 11. Inputs for NPP-HTSE and NPP-LTE.

Parameters	HTSE	LTE	Notes
Power Requirement	500 MW-dc 538 MW-ac	500 MW-dc 551 MW-ac	DC power corresponds to stack power input and is assumed to be the same for both HTSE and LTE. AC power corresponds to the total power requirement for electrolysis, including AC power to rectifier, pumps, topping heaters, etc. The conversion rate for HTSE and LTE are different based on [3] and [33].

Parameters	HTSE	LTE	Notes
Plant Life	20 years	20 years	Default value in [3] and assumed the same for both HTSE and LTE.
Maximum PTC for hydrogen production	\$3/kg-H_2	\$3/kg-H_2	IRA Section 45V related to maximum PTC for 10 years with base rate of $0.6 and multiplication factor of 5.
Utilities Usage			
Process Water Feed Rate Cooling Water Circ. Rate	36 kg /s (577 gpm) 585 kg /s (9290 gpm)	55 kg/s (864 gpm) 0 kg/s (0 gpm)	The process water and cooling water rate for HTSE came from the HYSYS [40] model output while those for LTE came from [33].
Utilities Costs ($20222)			
Process Water	$0.0027917/gal	$0.0027917/gal	Process water costs used the default value in $2020 from [3] for both HTSE and LTE.
Cooling Water	$0.0000279/gal	$0/gal	
Plant Design Capacity	351 tonne/day H_2	231 tonne/day H_2	The capacity for hydrogen production coming from the mass-flow rate (8.124 kg-H_2/sec) in HYSYS model [40] for HTSE while the hydrogen production rate for LTE is obtained from [33].
Energy Requirement			
Electricity Required	36.79 kWh-e (ac)/kg-H_2	57.26 kWh-e (ac)/kg-H_2	Energy requirement for HTSE is from [3] while energy requirement for LTE is from [33].
Thermal Energy Required	6.4 kWh-t/kg-H_2	0 kWh-t/kg-H_2	
Utilities Usage			
Process Water	1183 gallon/ tonne H_2	3780 gallon/ tonne H_2	The process and coolant water usage come from the HTSE model considering the ambient cooling entering at 20°C and exiting at 34°C (compress hydrogen and sweep water cycle; knock out the water). The process water usage coming from [33].
Cooling Water	19077 gallon/ tonne H_2	\$0/gal /tonne H_2	
Stack Cost ($2022)	$153/kW-dc (1000 MW/yr mfg)	$486/kW-dc (1000 MW/yr mfg)	For HTSE, $78/kw-dc in 2020 is obtained from the value reported from Design for Manufacturing and Assembly analysis of an electrode-supported cell stack with specified manufacturing rates [3] with an additional a contingency of 10% and stack cost markup of 30%. The stack costs of LTE are obtained from [33] and inflated from 2019 to 2022 using CEPCI.
BOP Costs ($2022)	$450/kW-dc	$162/kW-dc	
DCC excluding integration costs ($2022)	$603/kW-dc	$545/kW-dc	Includes the capital cost of the nuclear process heat delivery system; excludes costs of any required NPP modifications for integration with HTSE or LTE.
	(Stack costs: 17%)	(Stack costs: 75%)	
	(BOP costs: 83%)	(BOP costs: 25%)	

Parameters	HTSE	LTE	Notes
Integration costs ($2021)	$64 million	$32 million	The costs associated with mechanical interface and switchyard from S&L design [9].
Indirect Capital costs including contingency ($2022)	$249/kW-dc	$226/kW-dc	Include costs associated with site preparation, engineering and design, contingency.
Land Costs ($2022)	$10/KW-dc	$8/KW-dc	
Total Capital Investment including integration costs ($2022)	$1009/kW-dc	$853/kW-dc	Includes direct and indirect capital costs that are depreciable and the non-depreciable capital costs such as land costs for both HTSE and LTE.
Total Fixed Operations and Maintenance (O&M) Costs ($2022)	$494/kW-dc	$433/kW-dc	The present value of the total fixed O&M costs including labor, general and administration, property tax and insurance, and production maintenance and repairs.
Total Stack Replacement Costs ($2022)	$357/kW-dc	$772/kW-dc	The present value of the total replacement costs with consideration of 0.5% of unplanned replacement cost and fixed replacement cost at the end of the stack service life.

5.3.2 Financial Performance

This section compares LCOH with and without hydrogen delivery costs and the delta NPV of cashflows for Cases 1A, 1B, 2A, and 2B before and after tax for five different plants. Other financial parameters, such as IRR, NPV_{H2}, and NPV_{BAU}, as well as the raw data for the plots in this section are documented in Appendix B.

Figure 28 compares the LCOH without hydrogen delivery costs for the selected case studies defined in Section 5.2 for Waterford 3, Riverbend, Grand Gulf, South Texas, and Comanche Peak. The error bars represent the LCOH variations based on the electricity price, which ranges from $30 to 40/MWh for Waterford, Riverbend, and Grand Gulf and from $23 to $90/MWh for STP and CP. The calculated LCOH is the breakeven costs for each case that leads to zero NPV of cashflows. The taxes here include the income state and federal tax payment as well as potential tax credits from IRA 45 V.

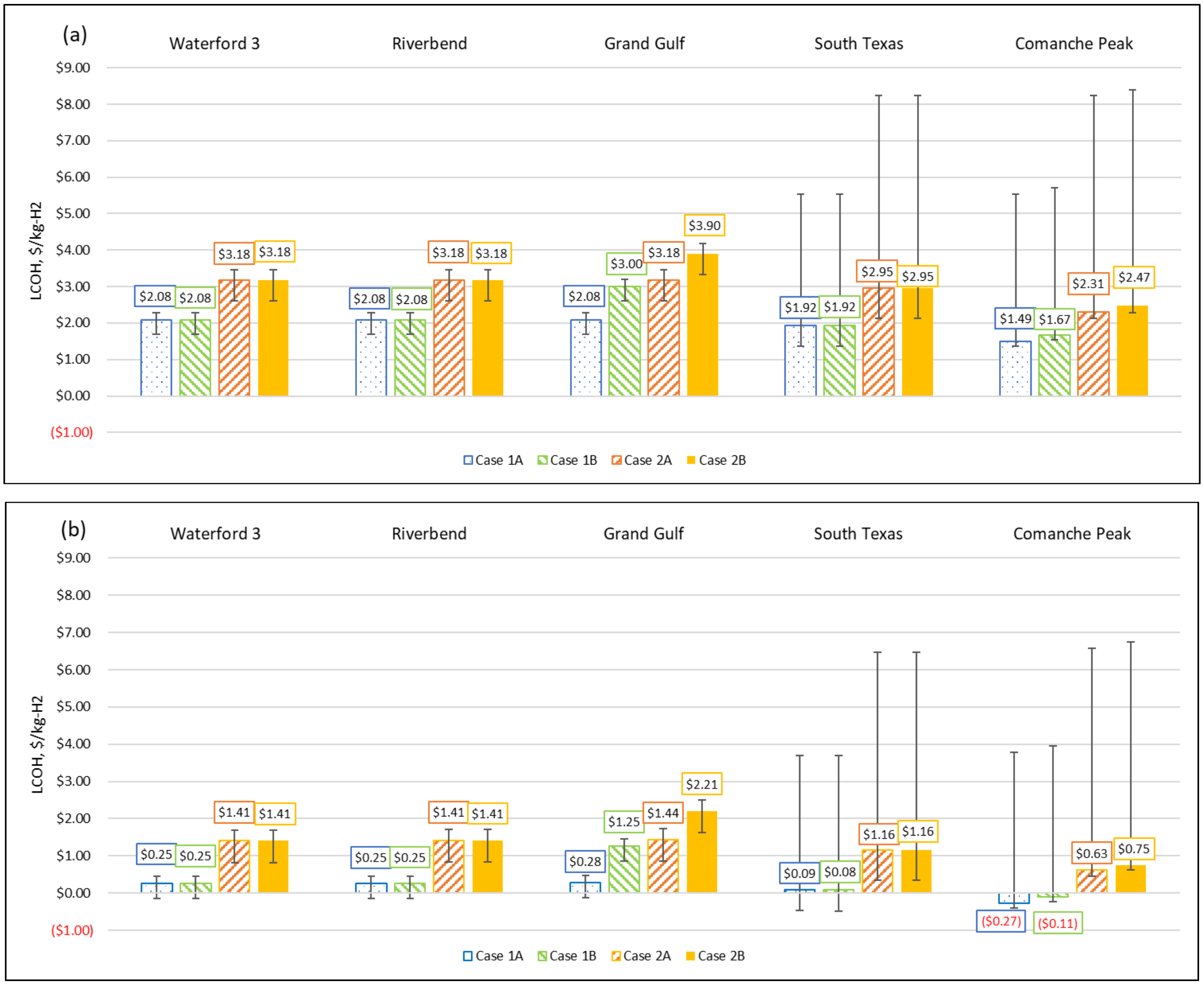


Figure 28. LCOH production without hydrogen-delivery costs for the selected cases in various plants (a) before and (b) after taxes.

From Figure 28, both the LCOHs before and after taxes of Cases 1A and 1B for all the plants are less than those of Cases 2A and 2B, respectively. This is because the HTSE has a higher hydrogen-production rate than LTE at the same energy demand. This observation indicates that producing hydrogen through HTSE yields higher economic benefit than production using LTE. Cases 1A and 1B share the same LCOHs for Waterford, Riverbend and South Texas NPP because the maximum amount of hydrogen from each plant is produced to meet the demand. The same situation is applied for Cases 2A and 2B, where the estimated LCOH before incorporating the transportation costs are the same. The LCOH for Cases 1B and 2B are slightly higher than those in Cases 1A and 1B for the Grand Gulf and Comanche Peak plants due to the reduction in hydrogen demand from supplying the hydrogen pipeline to the individual industrial users and corresponding size of the electrolyzers. Typically, the larger the size, the lower the LCOHs. Therefore, it is recommended to build a pipeline network that can benefit most of industrial users instead of building an individual pipeline that would be far away from hydrogen-production facilities. Comparing Figure 28 (a) and (b), the cases after taxes including the tax credits significantly reduce the LCOH, by about \$1.8/kg-H_2. Note that the benefit of tax credits on hydrogen production is not exactly \$3/kg-H_2 because the IRA 45U can be claimed for 10 years based on the current policy.

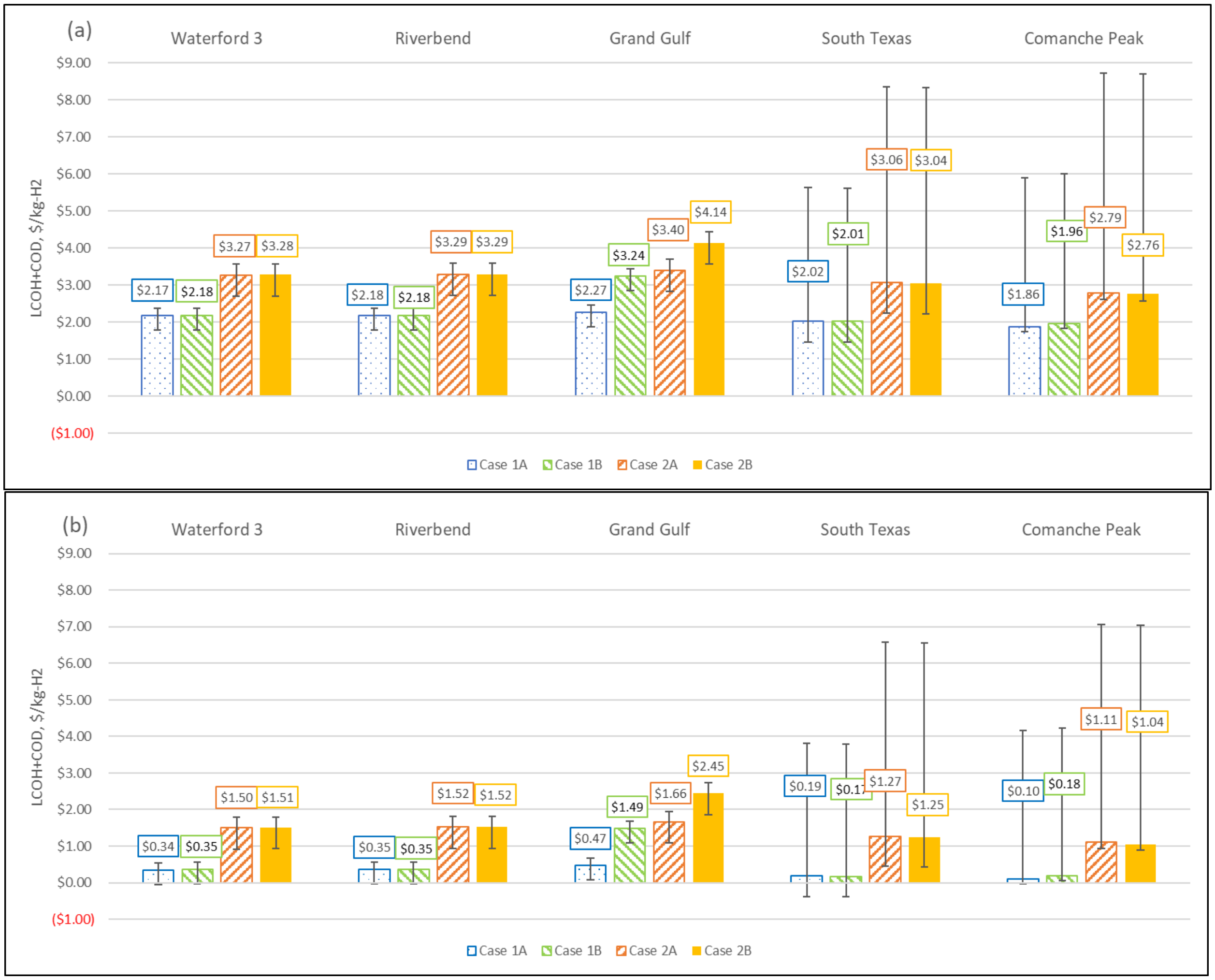


Figure 29. LCOH production with hydrogen delivery costs for the selected cases in various plants (a) before and (b) after taxes.

As shown in Figure 29, hydrogen-delivery costs have insignificant impact on the overall costs of the hydrogen production (LCOH) and delivery (COD). The maximum hydrogen delivery cost is no more than \$0.5/kg-H_2 at the Comanche Peak plants due to a greater distance of hydrogen transportation and relatively low demand in this region compared to the other locations. By contrast, the overall cost of hydrogen production and delivery at Waterford and Riverbend are lowest relative to other locations due to high demand and shorter distance to the nearby hydrogen pipeline and the industrial users. Assuming the hydrogen market price is equivalent to the summation of LCOH and COD [41] , the NPV of cashflows in hydrogen production (NPV_{H2}) can be compared with the NPV of cashflows in the BAU (NPV_{BAU}) to form another metric defined as delta NPV, shown in Figure 30.

Figure 30. Delta NPV of cashflows for selected cases in various plants (a) before and (b) after taxes.

From Figure 30 (a), the delta NPV of cashflows is always negative for all the cases, indicating that producing hydrogen before considering tax credits is less profitable than purely selling the electricity to the grid, given that the electricity price for selling to the grid is the same as the costs of the electricity to produce hydrogen. However, in practice, the cost of the electricity may be slightly lower than the selling price, which may make the delta NPV of cashflows for some cases in Figure 30 (a) positive. Future research would explore the detailed costs of the electricity from each plant and the possibility to generate scenarios that are profitable before considering the taxes.

From Figure 30 (b), the delta NPV of cashflows for HTSE (Cases 1A and 1B) are all positive for various locations, indicating that hydrogen production through HTSE is preferred after taxes when including the PTCs in IRA Section 45V. While the LTE utilized much more electricity compared to HTSE, resulting in a higher NPV_{BAU} of cashflows for Cases 2A and 2B, the delta NPV of cashflows for Cases 1A and 2A are much higher than for Cases 2A and 2B. The delta NPV of cashflows for Waterford, Riverbend and Grand Gulf for Case 1A (delivered to the nearby pipelines) are the highest, meaning that producing hydrogen onsite, close to these plants, may yield the highest profitability relative to other regions in the Gulf Coast.

5.3.3 Sensitivity Analysis

The sensitivity studies with respect to LCOH and the NPV_{H2} of cashflows after taxes for nuclear-integrated hydrogen production using HTSE and LTE are performed based on the selected inputs: DCCs, indirect capital costs multipliers, stack-degradation rates, hydrogen market price, electricity price, NPP capacity factor, and HTSE or LTE plant capacity. Table 12 shows the lower, nominal, and upper bounds for the selected input parameters used in the sensitivity studies.

Table 12. Lower, nominal, and upper bounds of the selected parameters for sensitivity studies with respect to LCOH with PTC and the NPV_{H2} of cashflows with PTC.

Performance Metrics	Lower Bound	Nominal Value	Upper Bound	Note
HTSE Direct Capital Costs ($M)	151	301	900	50% variation of the nominal value is assumed for the lower bound. 900 M is assumed for the upper bound based on the feedback from the industry.
LTE Direct Capital Costs ($M)	136	273	900	50% variation of the nominal value is assumed for upper and lower bound. 900 M is assumed for the upper bound based on the feedback from the industry.
Indirect Capital Costs Multipliers	20%	41%	50%	The lower and upper bounds are selected based on the internal discussion.
Weighted Average Cost of Capital	5%	5.7%	10%	The typical range between 5 to 10% is assumed to cover all different industries.
Hydrogen Market Price (LCOH+COD)	0.9	2.50	7.00	Lower and upper bounds are specified based on the results from Figure 29.
Electricity Price ($/MWh)	17	35	122	90% confidence interval for the Electric Reliability Council of Texas data in 2022, which includes the South Texas Project and Comanche Peak plant. Note that this range also covers the electricity price in Entergy plants such as Waterford, Riverbend and Grand Gulf.
NPP Capacity Factor	73%	93%	100%	The following information from existing NPP shows the ranges of the capacity factor for Waterford 3 (77%), Riverbend (100%), Grand Gulf (73%), South Texas (95%), and Comanche Peak (94%) as of 2022.
Electrolyzer Plant Capacity (MW-dc)	100	500	500	Based on the previous study [5] any plants that are less than 100 MW-dc would not be profitable.

Figure 31 and Figure 32 show the results of sensitivity studies using the tornado charts, where the inputs are changed one at a time with respect to the output of interest (i.e., LCOH and delta NPV of cashflows after taxes). The sensitivity studies on LCOH for HTSE and LTE plants are shown in Figure 31 while the sensitivity studies on delta NPV of cashflows are shown in Figure 32. The inputs are ranked based on the sensitivity, which is defined by the ranges of the maximum and minimum of the outputs in Table 12.

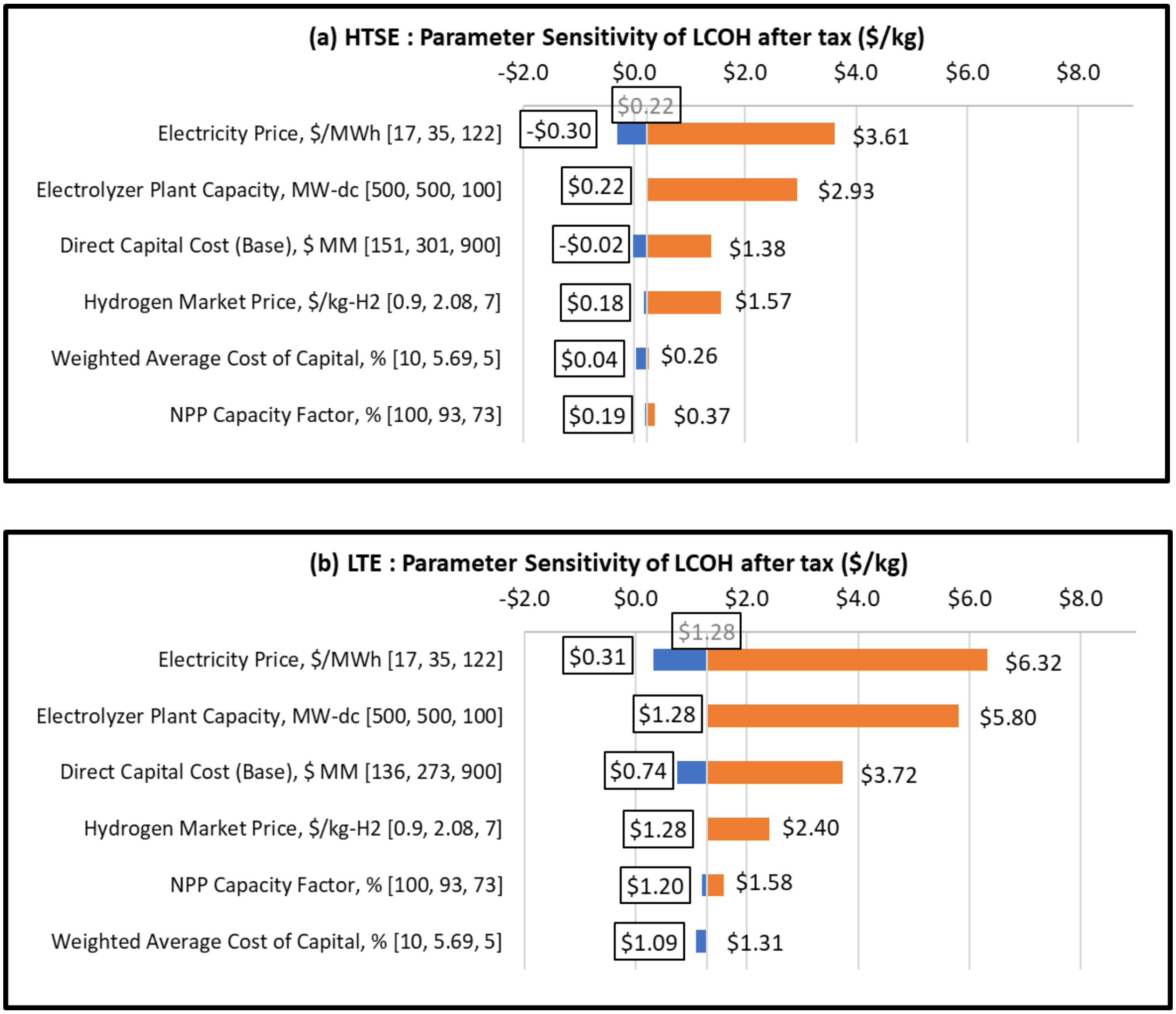


Figure 31. Sensitivity studies of LCOH before taxes for (a) HTSE plants and (b) LTE plants with the upper and lower bounds defined in Table 12. The nominal value is taken from Case 1A for Waterford plant.

The sensitivity studies depicted in Figure 31 show that all selected inputs for estimating LCOH yield the same ranking for both HTSE and LTE. The sensitivity study includes plant variability, and there is no need to generate other plots for different plants. The electricity price is the most-sensitive parameter for LCOH estimation while the second most-sensitive parameter is electrolyzer-plant capacity. This is because electricity is the main feed for hydrogen production while electrolyzer-plant capacity affects daily hydrogen production. In practice, there is dependency between electrolyzer-plant capacity and the DCC. That is, the larger the plant, the higher the cost of the DCCs [3], which would impact overall capital costs, including direct and indirect costs estimation. However, the impacts of DCCs are relatively small compared to the electricity price and the electrolyzer-plant capacity. A more-accurate sensitivity study can be done by performing a global sensitivity study once non-linear behavior is observed between the selected input parameters and the performance metrics. [42]

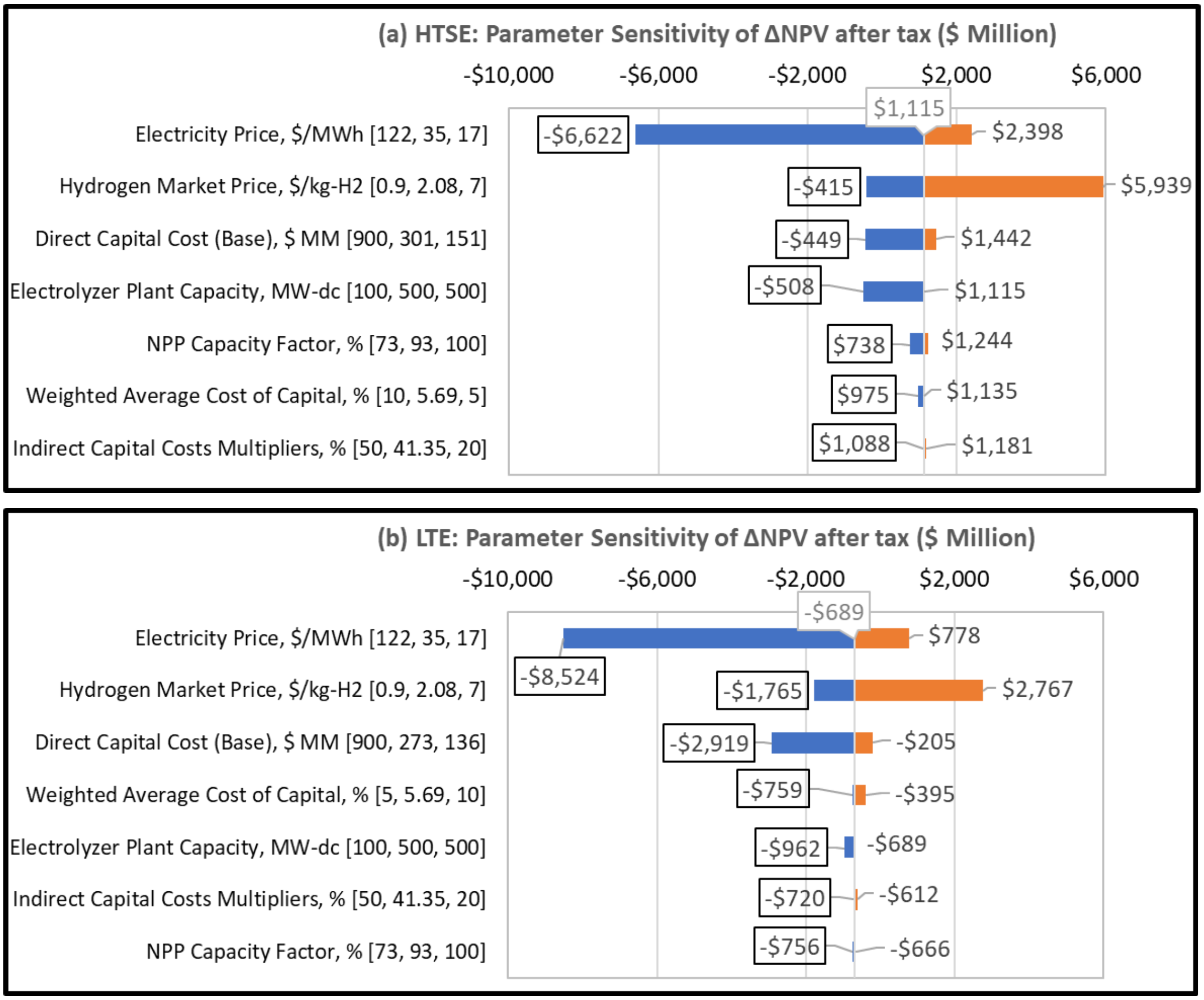
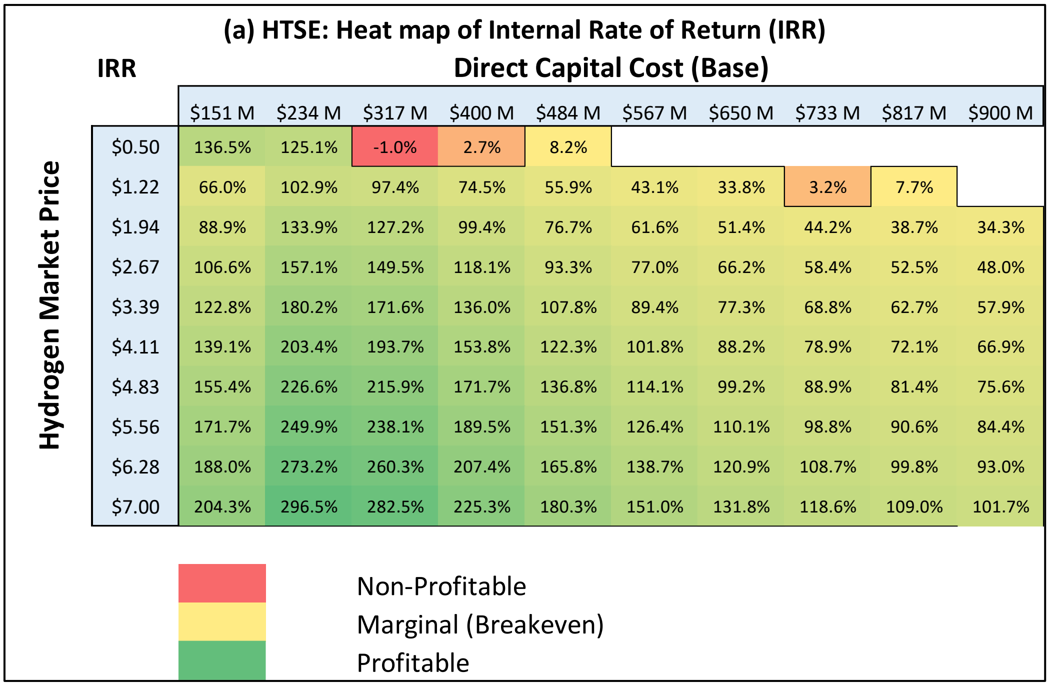


Figure 32. Sensitivity studies of taxed NPV_{H2} of cashflows for Case 1b and 2(b) with the upper and lower bounds defined in Table 12. The nominal value is taken from Case 2A for Waterford plant.

From Figure 32, the top two most sensitive parameters for estimating the delta NPV of cashflows are electricity price and hydrogen market price. The electricity price is the cost of hydrogen production while the revenue is from selling electricity to the grid in the BAU case. From the perspective of hydrogen production, the maximum NPV would be achieved when electricity price is low while the hydrogen market price is high. In addition, while increasing electrolyzer-plant capacity can result in increased hydrogen production, resulting in more revenue earned, the revenue of the electricity sale would also increase, resulting in a negative NPV of cashflows for the maximum 500 MW-dc case.

5.3.4 Profitability Analysis using heat maps

In addition to electricity price, the hydrogen market price and direct capital costs are sensitive to the LCOH and delta NPV estimation. Therefore, the profitability analysis is executed by calculating IRR and NPV_{H2} after taxes. The profitable condition is determined when the IRR is greater than the WACC and the NPV_{H2} is positive. Figure 33 and Figure 34 demonstrate the profitable conditions for HTSE and LTE, respectively.

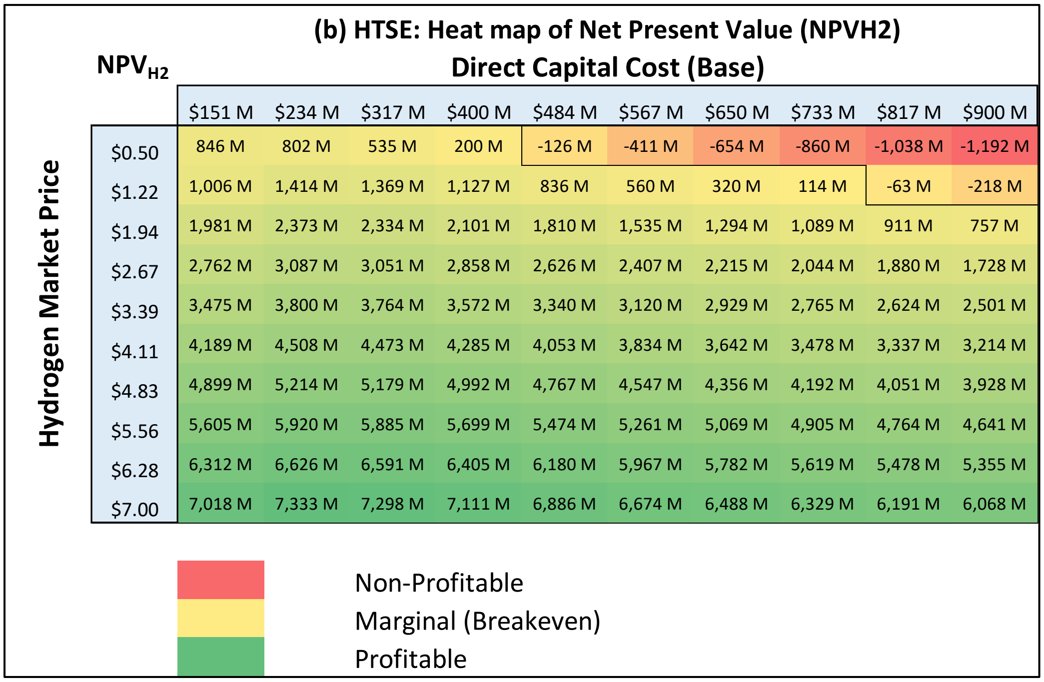


(a) HTSE: Heat map of Internal Rate of Return (IRR)

IRR — **Direct Capital Cost (Base)**; rows: **Hydrogen Market Price**

IRR	$151 M	$234 M	$317 M	$400 M	$484 M	$567 M	$650 M	$733 M	$817 M	$900 M
$0.50	136.5%	125.1%	-1.0%	2.7%	8.2%					
$1.22	66.0%	102.9%	97.4%	74.5%	55.9%	43.1%	33.8%	3.2%	7.7%	
$1.94	88.9%	133.9%	127.2%	99.4%	76.7%	61.6%	51.4%	44.2%	38.7%	34.3%
$2.67	106.6%	157.1%	149.5%	118.1%	93.3%	77.0%	66.2%	58.4%	52.5%	48.0%
$3.39	122.8%	180.2%	171.6%	136.0%	107.8%	89.4%	77.3%	68.8%	62.7%	57.9%
$4.11	139.1%	203.4%	193.7%	153.8%	122.3%	101.8%	88.2%	78.9%	72.1%	66.9%
$4.83	155.4%	226.6%	215.9%	171.7%	136.8%	114.1%	99.2%	88.9%	81.4%	75.6%
$5.56	171.7%	249.9%	238.1%	189.5%	151.3%	126.4%	110.1%	98.8%	90.6%	84.4%
$6.28	188.0%	273.2%	260.3%	207.4%	165.8%	138.7%	120.9%	108.7%	99.8%	93.0%
$7.00	204.3%	296.5%	282.5%	225.3%	180.3%	151.0%	131.8%	118.6%	109.0%	101.7%

🟥 Non-Profitable
🟨 Marginal (Breakeven)
🟩 Profitable



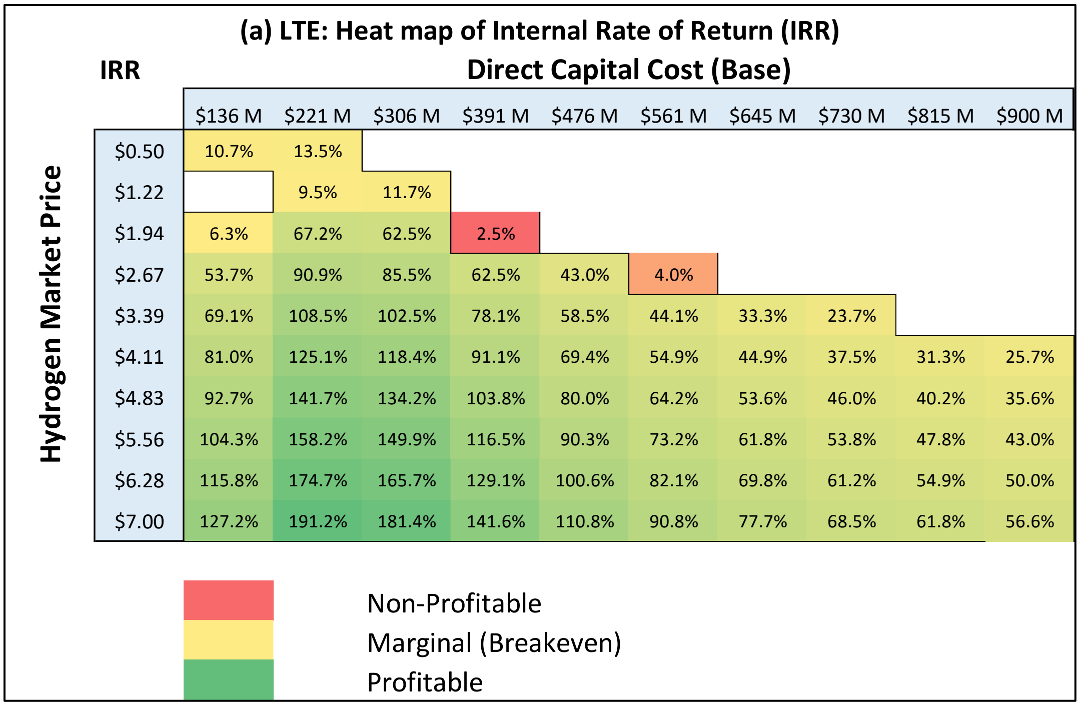
(b) HTSE: Heat map of Net Present Value (NPVH2)

NPV_{H2} — **Direct Capital Cost (Base)**; rows: **Hydrogen Market Price**

NPV_{H2}	$151 M	$234 M	$317 M	$400 M	$484 M	$567 M	$650 M	$733 M	$817 M	$900 M
$0.50	846 M	802 M	535 M	200 M	-126 M	-411 M	-654 M	-860 M	-1,038 M	-1,192 M
$1.22	1,006 M	1,414 M	1,369 M	1,127 M	836 M	560 M	320 M	114 M	-63 M	-218 M
$1.94	1,981 M	2,373 M	2,334 M	2,101 M	1,810 M	1,535 M	1,294 M	1,089 M	911 M	757 M
$2.67	2,762 M	3,087 M	3,051 M	2,858 M	2,626 M	2,407 M	2,215 M	2,044 M	1,880 M	1,728 M
$3.39	3,475 M	3,800 M	3,764 M	3,572 M	3,340 M	3,120 M	2,929 M	2,765 M	2,624 M	2,501 M
$4.11	4,189 M	4,508 M	4,473 M	4,285 M	4,053 M	3,834 M	3,642 M	3,478 M	3,337 M	3,214 M
$4.83	4,899 M	5,214 M	5,179 M	4,992 M	4,767 M	4,547 M	4,356 M	4,192 M	4,051 M	3,928 M
$5.56	5,605 M	5,920 M	5,885 M	5,699 M	5,474 M	5,261 M	5,069 M	4,905 M	4,764 M	4,641 M
$6.28	6,312 M	6,626 M	6,591 M	6,405 M	6,180 M	5,967 M	5,782 M	5,619 M	5,478 M	5,355 M
$7.00	7,018 M	7,333 M	7,298 M	7,111 M	6,886 M	6,674 M	6,488 M	6,329 M	6,191 M	6,068 M

🟥 Non-Profitable
🟨 Marginal (Breakeven)
🟩 Profitable

Figure 33. Profitability analysis for HTSE by calculating (a) internal rate of return, and (b) net present value hydrogen production with respect to different values of direct capital costs and hydrogen market price.



(a) LTE: Heat map of Internal Rate of Return (IRR)

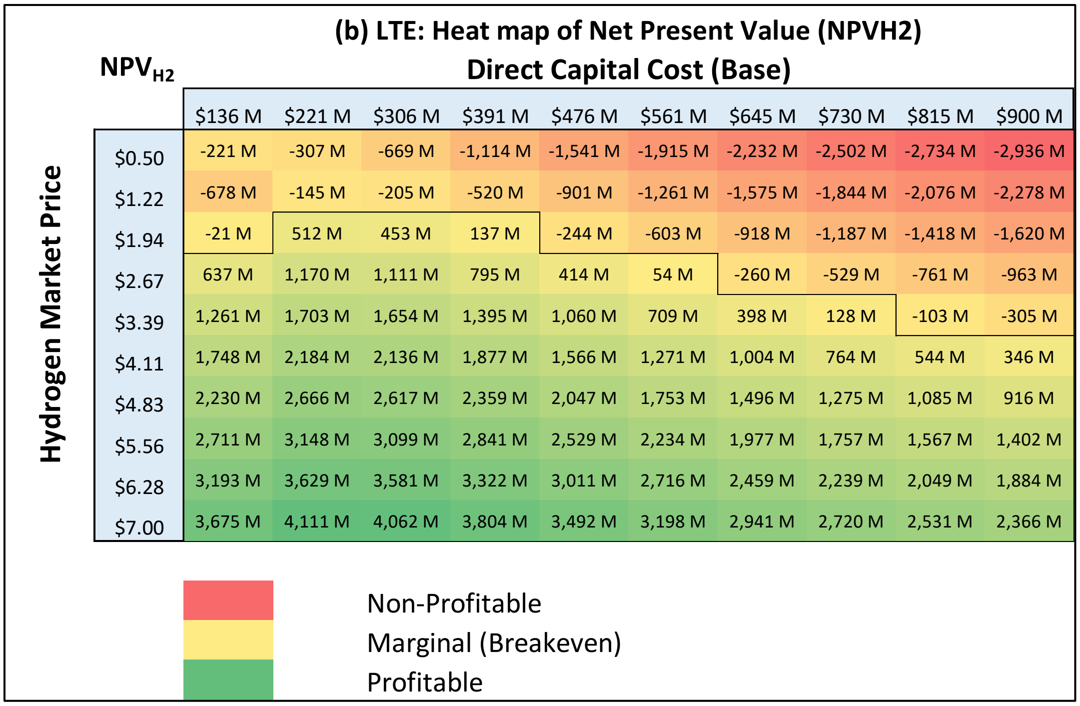
Direct Capital Cost (Base)

IRR Hydrogen Market Price	$136 M	$221 M	$306 M	$391 M	$476 M	$561 M	$645 M	$730 M	$815 M	$900 M
$0.50	10.7%	13.5%								
$1.22		9.5%	11.7%							
$1.94	6.3%	67.2%	62.5%	2.5%						
$2.67	53.7%	90.9%	85.5%	62.5%	43.0%	4.0%				
$3.39	69.1%	108.5%	102.5%	78.1%	58.5%	44.1%	33.3%	23.7%		
$4.11	81.0%	125.1%	118.4%	91.1%	69.4%	54.9%	44.9%	37.5%	31.3%	25.7%
$4.83	92.7%	141.7%	134.2%	103.8%	80.0%	64.2%	53.6%	46.0%	40.2%	35.6%
$5.56	104.3%	158.2%	149.9%	116.5%	90.3%	73.2%	61.8%	53.8%	47.8%	43.0%
$6.28	115.8%	174.7%	165.7%	129.1%	100.6%	82.1%	69.8%	61.2%	54.9%	50.0%
$7.00	127.2%	191.2%	181.4%	141.6%	110.8%	90.8%	77.7%	68.5%	61.8%	56.6%

🟥 Non-Profitable

🟨 Marginal (Breakeven)

🟩 Profitable



(b) LTE: Heat map of Net Present Value (NPVH2)

Direct Capital Cost (Base)

NPV_{H2} Hydrogen Market Price	$136 M	$221 M	$306 M	$391 M	$476 M	$561 M	$645 M	$730 M	$815 M	$900 M
$0.50	-221 M	-307 M	-669 M	-1,114 M	-1,541 M	-1,915 M	-2,232 M	-2,502 M	-2,734 M	-2,936 M
$1.22	-678 M	-145 M	-205 M	-520 M	-901 M	-1,261 M	-1,575 M	-1,844 M	-2,076 M	-2,278 M
$1.94	-21 M	512 M	453 M	137 M	-244 M	-603 M	-918 M	-1,187 M	-1,418 M	-1,620 M
$2.67	637 M	1,170 M	1,111 M	795 M	414 M	54 M	-260 M	-529 M	-761 M	-963 M
$3.39	1,261 M	1,703 M	1,654 M	1,395 M	1,060 M	709 M	398 M	128 M	-103 M	-305 M
$4.11	1,748 M	2,184 M	2,136 M	1,877 M	1,566 M	1,271 M	1,004 M	764 M	544 M	346 M
$4.83	2,230 M	2,666 M	2,617 M	2,359 M	2,047 M	1,753 M	1,496 M	1,275 M	1,085 M	916 M
$5.56	2,711 M	3,148 M	3,099 M	2,841 M	2,529 M	2,234 M	1,977 M	1,757 M	1,567 M	1,402 M
$6.28	3,193 M	3,629 M	3,581 M	3,322 M	3,011 M	2,716 M	2,459 M	2,239 M	2,049 M	1,884 M
$7.00	3,675 M	4,111 M	4,062 M	3,804 M	3,492 M	3,198 M	2,941 M	2,720 M	2,531 M	2,366 M

🟥 Non-Profitable

🟨 Marginal (Breakeven)

🟩 Profitable

Figure 34. Profitability analysis for LTE by calculating (a) internal rate of return, and (b) net present value hydrogen production with respect to different values of direct capital costs and hydrogen market price..

From Figure 33, hydrogen production through HTSE is profitable when direct capital costs is low while the hydrogen market price is high. The green and yellow regions in Figure 33 shows the profitable conditions where IRR is greater than WACC with positive NPV. The utilities can take the heat maps as references to decide whether the estimated direct capital costs of electrolyzer and hydrogen market price can make a profitable condition. Comparing Figure 34 and Figure 33, using HTSE for hydrogen production has a wider range of the profitable conditions compared to those using LTE.

5.3.5 LCOH Comparisons Between Nuclear Integrated Hydrogen and Blue Hydrogen

The competitive analysis is done in the NIHPA tool by comparing two major quantities: (1) LCOHs of nuclear-integrated hydrogen production with and without PTC, (2) LCOHs of SMR with and without carbon-capture sequestration (CCS). The results of comparisons are shown in Figure 35 and Figure 36, where (a) represents the results for NPP-HTSE or Case 1A while (b) shows the results for NPP-LTE or Case 2A.

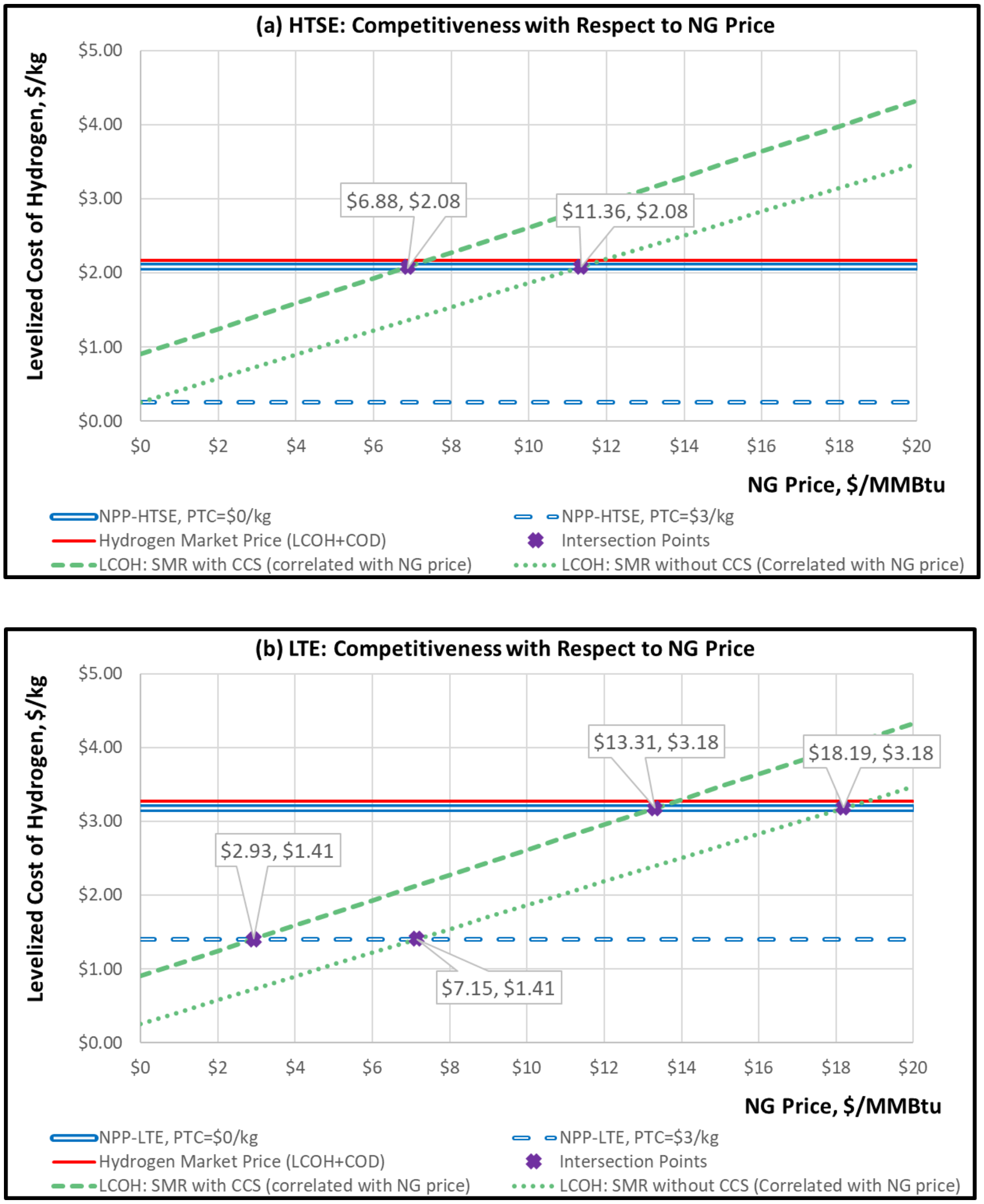


Figure 35. Competitive analysis with respect to natural gas for hydrogen production through (a) HTSE or (b) LTE with 500 MW-dc of electrolysis design capacity, 20 years of plant life, 5.66% of WACC, user-defined electricity fixed price, and hydrogen market price equivalent to summation of LCOH and COD.

From Figure 35 (a), the LCOHs of nuclear-integrated hydrogen production (blue hollow lines) are independent of natural gas prices as consistent with the assumption, resulting in the horizontal lines. The LCOHs of SMR with and without CCS (green dashed lines) are strongly dependent on the natural gas price. The intersection points shown in Figure 35 (a) indicate a competitive natural gas price with respect to different scenarios. For example, the intersection point formed by the lines representing the nuclear-integrated hydrogen production with PTC and SMR with CCS shows that the nuclear-integrated hydrogen production through HTSE is competitive when natural gas price is in all ranges and the corresponding LCOH is $0.23 per kilogram of hydrogen production. On the other hand, the hydrogen production through LTE is competitive when natural gas price is more than $7.15 per MMBtu and the corresponding LCOH is $1.41 per kilogram of hydrogen production.

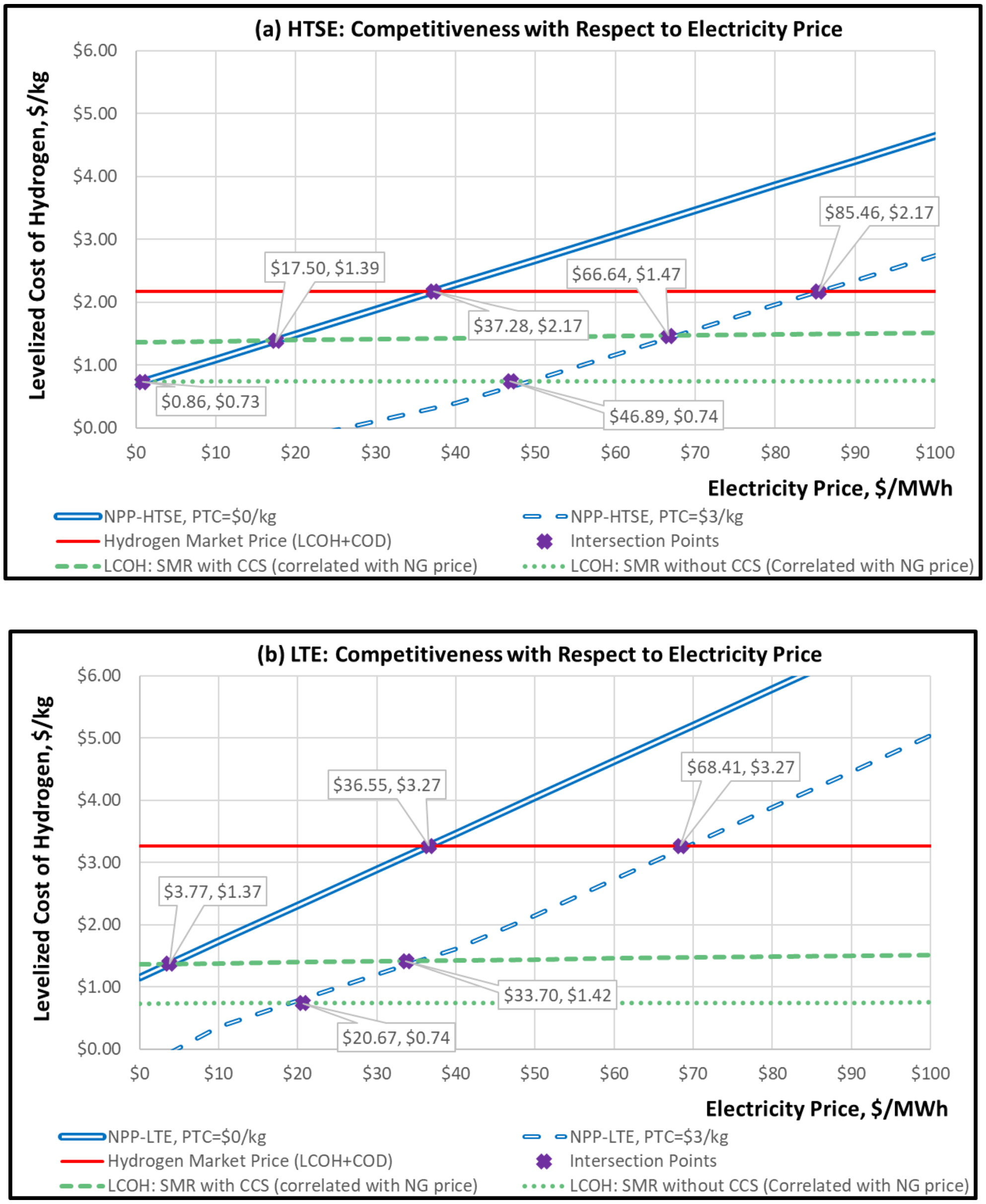


Figure 36. Competitive analysis with respect to electricity price for hydrogen production through (a) HTSE or (b) LTE with 500 MW-dc of electrolysis design capacity, 20 years of plant life, 5.7% of WACC, user-defined electricity fixed price, and hydrogen market price equivalent to summation of LCOH and COD.

From Figure 36 (a), both the LCOHs of nuclear-integrated hydrogen production (hollow blue lines) and the SMR (dashed green lines) are dependent on electricity price. However, the hollow blue lines are steeper than the dashed green lines because nuclear-integrated hydrogen production requires more electricity than SMR. The intersection points shown in Figure 36 (a) indicate a competitive electricity price with respect to different scenarios. For instance, the intersection point formed by the lines representing nuclear-integrated hydrogen production with PTC and SMR with CCS shows that the nuclear-integrated hydrogen production is competitive when electricity price is below $66.64/MWh for HTSE while it is competitive for LTE if the electricity price is below $33.70/MWh. This confirms that producing hydrogen using nuclear-powered HTSE is competitive with hydrogen production SMR when the electricity price is in the range of $25 to $40/MWh. LTE is competitive when the electricity price is in the range between $25 and $34/MWh.

Due to the limited WACC variability for the five plants, Figure 35 and Figure 36 are valid for Cases 1A and 2A for all the plants, as well as Cases 1B and 2B for Waterford, Riverbend, and South Texas NPPs where 500 MW-dc is assumed to produce the hydrogen. Table 9shows that only Grand Gulf and Comanche Peak have smaller electrolyzer sizes due to the relatively small hydrogen demand. The competitive analysis for Cases 1B and 2B for Grand Gulf and Comanche Peak are shown in Appendix C.

5.4 Avoided Cost of Carbon

Integrating renewable energy systems into an existing industrial facility reduces emissions but involves additional expenditures. The cost of avoiding carbon emissions in a new facility can be calculated by dividing the incremental costs of developing cleaner integrated energy systems by the total carbon mitigated by the new integrated energy system. Mathematically, this relationship is represented by Equation (1).

$$Integrated\ system\ plant\ onsite\ CO2\ avoidance\ cost\ \left(\frac{\$}{MTCO2}\right) = \frac{Integrated\ system\ plant\ Additional\ Cost(\frac{\$}{day})}{Avoided\ CO2(MT/day)} \tag{1}$$

where

The additional cost from the facility that includes an integrated energy system is the difference between the total cost (CAPEX + O&M costs) in scenario “i” and the total cost in the BAU case.

The avoided CO_2 is the difference between the total CO_2 emissions from the plant in scenario “i” and the total CO_2 emissions from the plant in scenario BAU.

Additionally, it is possible to estimate the avoided net cost of carbon considering what would be the cost if tax credits are included, according to Equation (2).

$$Integrated\ system\ plantonsite\ CO2\ avoidance\ net\ cost\ \left(\frac{\$}{MTCO2}\right) = \frac{Integrated\ system\ plant\ additional\ Cost\left(\frac{\$}{day}\right) - PTC\left(\frac{\$}{MWh}\right) - ITC(\frac{\$}{CAPEX\%})}{Avoided\ CO2(MT/day)} \tag{2}$$

where

PTC is the dollars received from the tax credit 45V for 10 years since the plant starts operations.

ITC is the dollars received as a percentage of the CAPEX according to the investment tax credit 48E.

The Gulf Coast study examines the production of clean hydrogen from the electrolysis process with nuclear power from existing NPPs in the Gulf Coast region. This production pathway was compared to BAU conventional hydrogen production through SMR of natural gas. Carbon emissions were calculated using GREET GHG emissions data for both cases. The emissions for natural gas steam methane reforming are 9.4 kg CO_2e per kg of hydrogen and 0.35 kg CO_2e per kg of hydrogen for nuclear integrated HTSE. The carbon emissions and costs associated with these processes were used to develop the avoided cost of carbon as defined above. Also, tax credits were provided through IRA to reduce the cost of clean-hydrogen production, and these were incorporated into the calculation of the acc and defined as with and without tax credits. The study included the South Texas Project, Entergy's Waterford, Riverbend, and Grand Gulf NPPs, and Comanche Peak NPP in the avoided-cost-of-carbon evaluation.

Figure 37 presents the annual CO2 avoidance cost as a function of the total onsite CO2 avoidance for all scenarios, excluding the IRA ITCs and PTCs. As shown, the lower avoided carbon amounts and higher resultant avoided cost of carbon are associated with scenarios that supply a limited amount of hydrogen to such nearby demand centers as chemical plants and refineries. When the full volume of hydrogen from a 500-MW electrolysis unit is supplied to a pipeline or a complimentary demand center, the cost avoidance decreases by ~\$100/ton of avoided carbon and achieves the largest carbon reduction, as exhibited in Cases 1a and 2a for the NPPs. This relationship shows the impact of economies of scale for hydrogen production such that the avoided cost of carbon will be reduced as hydrogen production increases.

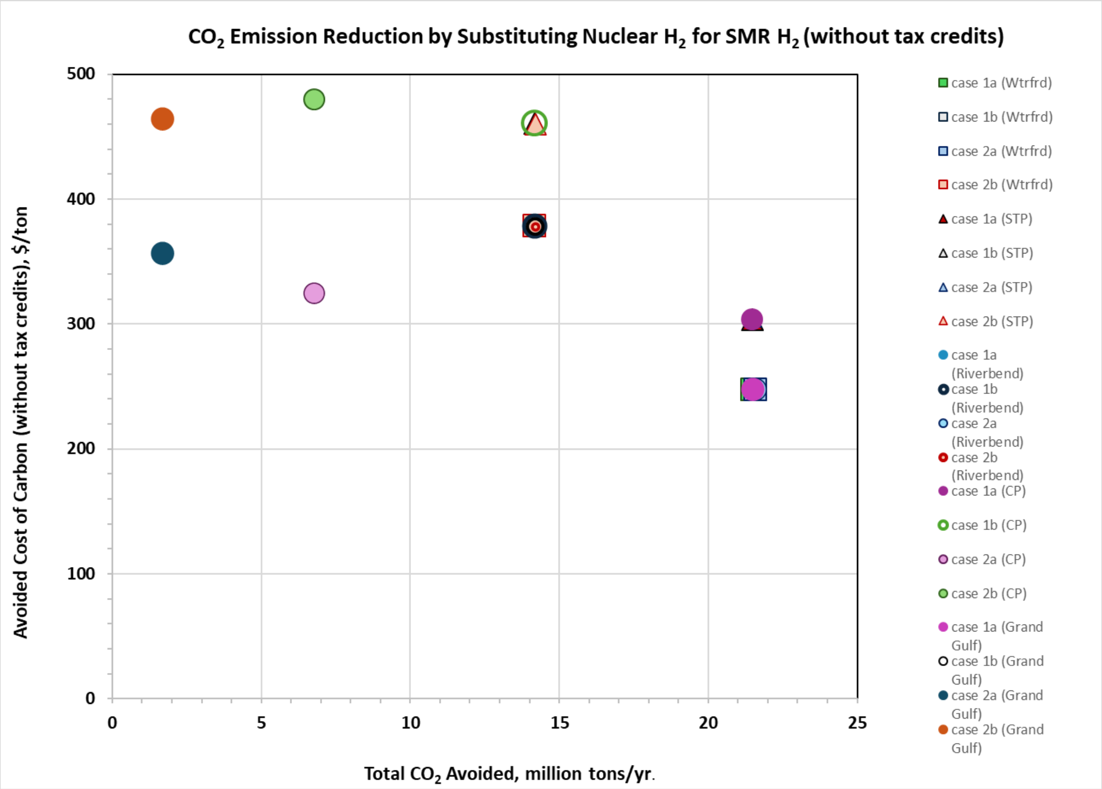


Figure 37. Total onsite CO_2 avoidance and annual cost by case without IRA ITCs and PTCs for Gulf Coast NPPs integrated with hydrogen production.

Figure 38 illustrates the impact of including the IRA ITCs and PTCs for electrolysis-based hydrogen production with energy from an NPP. The inclusion of the tax credits cases shows the avoided cost of carbon decreases by over $100/ton of carbon for all cases. The lower avoided carbon amounts and higher resultant avoided cost of carbon are associated with scenarios that supply limited hydrogen to such nearby demand centers as chemical plants and refineries. When the full volume of hydrogen from a 500-MW electrolysis unit is supplied to a pipeline or a complementary demand center, the decrease in avoided cost of carbon, to less than ~$100/ton of avoided carbon, achieves the largest carbon reduction, as exhibited in Cases 1a and 2a for the NPPs. This relationship continues to show the impact of economies of scale for hydrogen production such that the avoided costs will be reduced as hydrogen production increases.

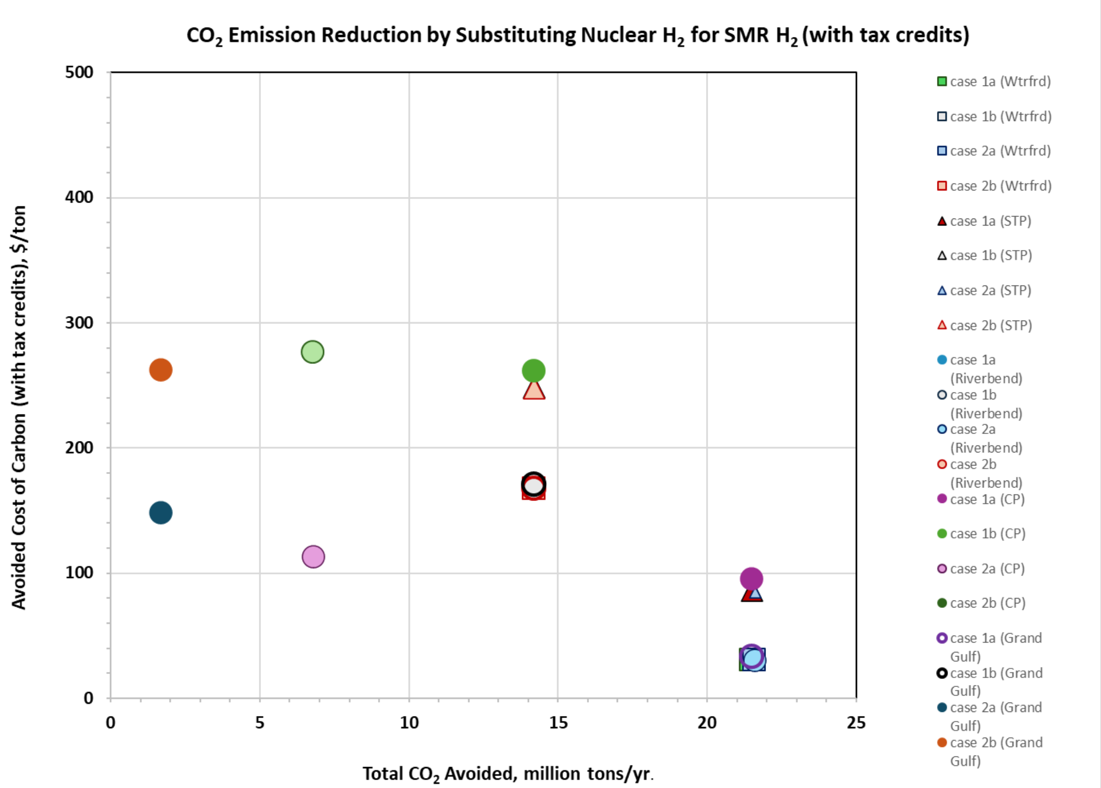


Figure 38. Total onsite CO_2 avoidance and annual cost by case with IRA ITCs and PTCs for Gulf Coast NPPs integrated with hydrogen production.

5.5 Preliminary HERON Analysis

The TEA done in Section 5.3 assumed a constant electricity price for the entire project lifetime (i.e., 20 years). In reality, the electricity price changes as a function of time. A constant electricity price is valid for regulated markets like Waterford, Riverbend, and Grand Gulf, where the price of electricity does not depend on the amount product sold on the market. However, for deregulated markets—South Texas Project and Commanche Peak—the electricity price may change based on the demand for and the amount of electricity sold to the grid. Utilities may take advantage of low costs for electricity to generate hydrogen in order to claim the tax credits while selling electricity to the grid when the electricity price is high. The Holistic Energy Resource Optimization Network (HERON) [43] is designed to solve this type of problem; it can optimize the revenue for a utility while satisfying the demands for different customers. HERON is a model for evaluating economic viability of electrical grids, integrated energy systems and other grid-energy configurations. This report will summarize the current status of HERON analysis to prepare a full scope of the HERON analysis in the future. Section 5.5.1 summarizes and intended scope of HERON analysis while Section 5.5.2 includes the process and the results to train a synthetic history of electricity price that is required to run a stochastic analysis in HERON.

5.5.1 Scope for HERON Analysis

The scope of HERON analysis is defined in Figure 39. Battery storage, hydrogen storage, and thermal storage for electricity, hydrogen, and steam are included in the scope to meet various demands in a timely manner and store energy for potential future demand. The costs associated with each component should be consistent with the previous section.

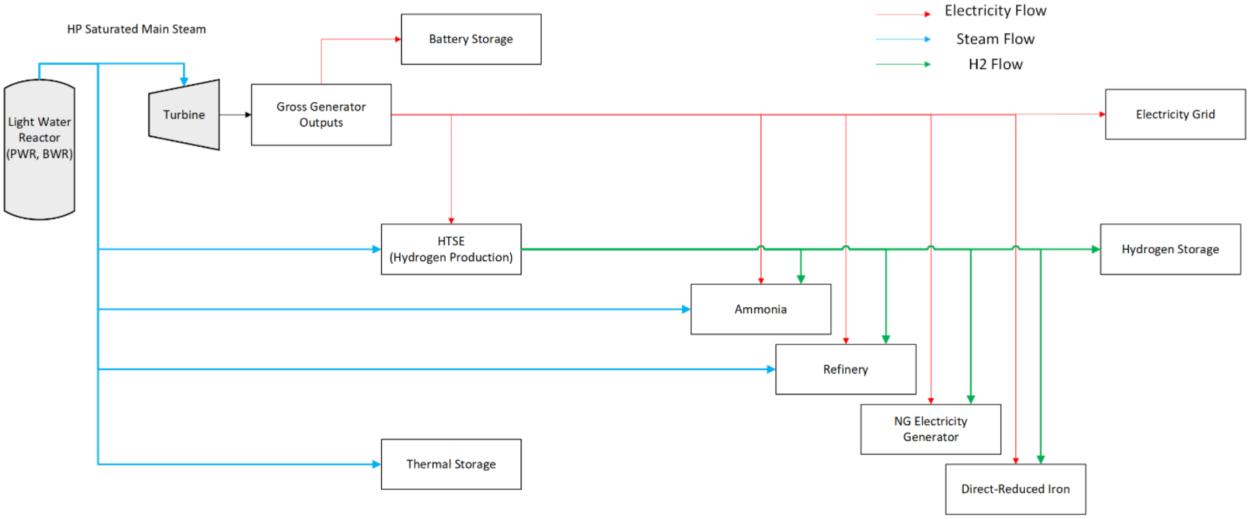


Figure 39. Product flow diagram for HERON analysis

5.5.2 Synthetic History Training for HERON Inputs

Price data typically present strong cyclic patterns, with a variety of periods—e.g., daily, weekly, and seasonally. In this study, we use Fourier series to simulate the cyclic trends and the autoregressive moving average (ARMA) model to simulate the random behaviors of the locational marginal price (LMP) profiles [44]. We use Risk Analysis Virtual Environment (RAVEN) [45] to perform our study. RAVEN is an open-source, Python-based flexible and multipurpose uncertainty-quantification, regression-analysis, probabilistic-risk-assessment, data-analysis, and model-optimization framework developed at INL [43].

Most LMP time series present a cyclic pattern because of the underlying correlation with the nodal load, which is driven by season and time of day. To detrend the periodic time series before fitting to the ARMA model, we use a Fourier time series shown in Equation (3).

$$x_t = y_t - \sum_m [a_m \sin(2\pi f_m t) + b_m \cos(2\pi f_m t)] = y_t - \sum_m c_m \sin(2\pi f_m t + \phi_m) \qquad (3)$$

where

$1/f_m$ is determined by the length of cycle, which is determined by base periods of the given time series. To identify the base periods of the LMP time series, we first transform the time series from time domain to frequency domain by applying fast Fourier transformation.

As shown in Figure 40, the frequency profiles clearly present several peaks that dominate the frequency domain. Note that in our Fourier analysis, 1 year is represented by 1 second; hence, the sample rate is 8760 Hz as a result of hourly resolution. Based on the peak frequency values, we have identified five base periods (note that frequency in parenthesis indicates the corresponding frequency of a base period): 1 day (365 Hz), 0.5 day (730 Hz), 182.5 days or half year (2 Hz), 1/3 day (1095 Hz), and 365 days (1 Hz).

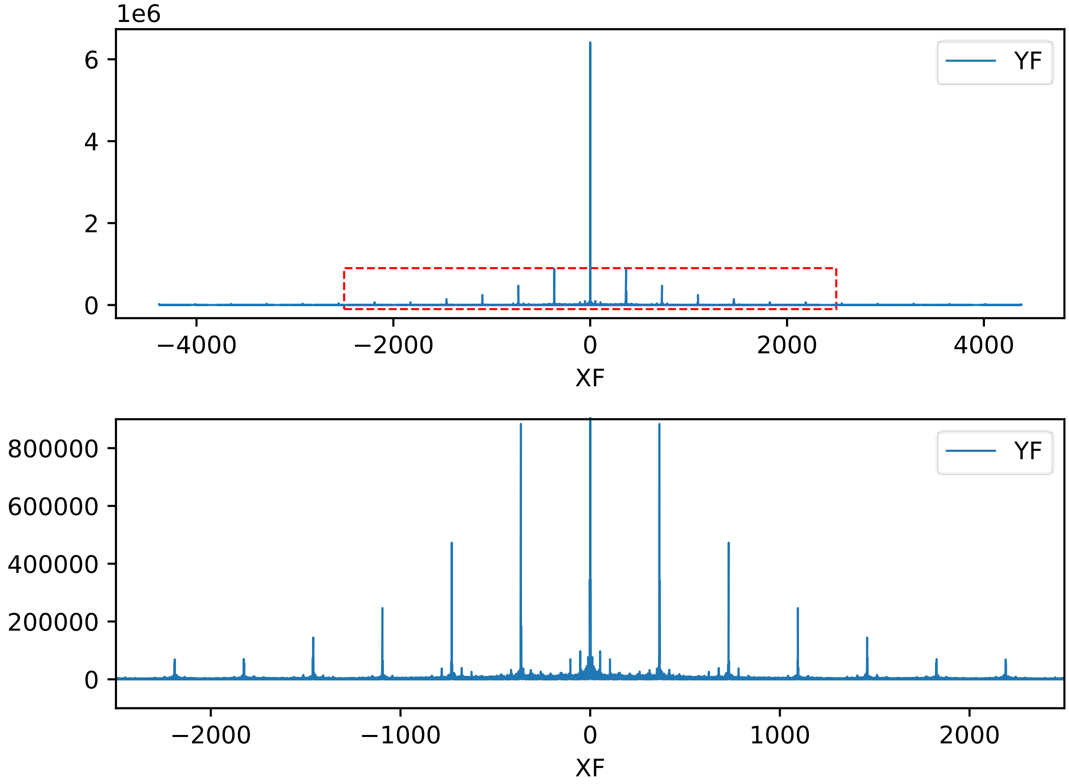


Figure 40. Results of fast Fourier transformation applied to the raw LMP time series. The bottom panel provides an expanded view of the red box in the top panel.

After the cyclic patterns are removed from the raw time series, the residual noises are modeled by the ARMA model. An ARMA model is a class of linear-time-series models that provide a general framework for describing a stationary stochastic process, described by Equation (4) [45].

$$x_t = \sum_{i=1}^{p} \phi_i x_{t-i} + \alpha_t + \sum_{j=1}^{q} \theta_j \alpha_{t-j} \qquad (4)$$

where

$x \in \mathbb{R}^n$, and $\phi_i, \theta_j \in \mathbb{R}^{n \times n}$.

The most important parameters in the ARMA model are p and q, which dictate the number of terms in the AR and MA models, respectively. Typically, greater p and q result in better fitting to the original data; however, it could also lead to overfitting. We therefore adopt Bayesian information criteria (BIC) to determine the optimal p and q values in our analysis. Specifically, we use a grid-search algorithm to find out the pair of (p, q) with the minimum BIC when both p and q are between 1 and 4. Given p and q, we use maximum-likelihood estimation to estimate the coefficients in Equation (4).

Plant specific data are used as raw input, which include 19 year's data, from 2024 to 2042, at hourly resolution. Applying the above method generates a set of synthetic data over the same period. Note that LMP values are assumed to be non-negative; therefore, the synthetic data are floored at zero. Because of the long timespan of the modeled period, only 4 weeks were selected to showcase the comparison between the raw and the generated time series, as presented in Figure 41. The two weeks chosen are in 2024, the first year in the modeled horizon, and the other two are from 2042, the last year. In both years, the synthetic data present better similarity to the raw data in summer than in winter in terms of profile shapes. Two major differences exist: first, winter-load profiles typically have two peaks per day, one in early morning and one in later afternoon, whereas summer profiles only have one peak, in the afternoon. Second, variations in winter are often smaller than summer, as depicted by their lower peaks.

Statistics of the scenarios are also compared to the raw data in Table 13. The synthetic data present means, medians, and standard deviations similar to the raw data, but differ significantly in terms of skewness and kurtosis, implying similar center positions but differing underlying distribution profiles, as also reflected by their probability density-distribution profiles in Figure 42. Both the mean and standard deviation present an increasing trend, suggesting both increasing LMP values and greater uncertainties into the future. The greater uncertainties in the far future are also reflected by wider and flatter distributions in 2042, as opposed to the narrower and higher distributions in 2024, also shown in Figure 42. Note that because the synthetic data are floored at 0, the resulting distributions are censored. Without the non-negativity constraint, distributions of the synthetic data should resemble a normal distribution.

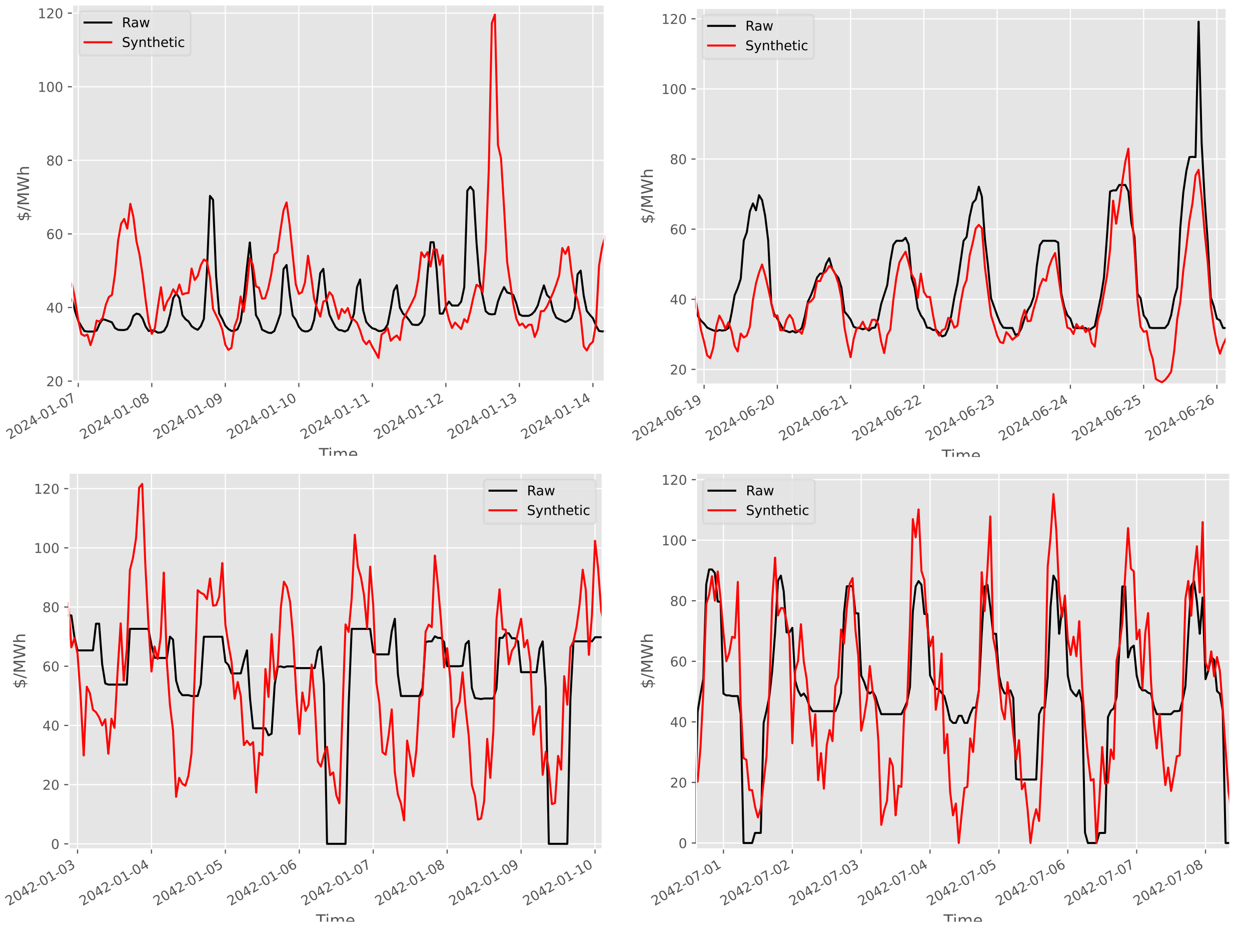


Figure 41. Comparison of the raw series and the synthetic time series. Top left: a winter week from 2024. Top right: a summer week from 2024. Bottom Left: a winter week from 2024. Bottom right: a summer week from 2042.

Table 13. Statistical characteristics of the raw and synthetic time series by year.

	Mean		Median		Standard deviation		Kurtosis		Skewness	
	Raw	Syn	Raw	Syn	Raw	Syn	Raw	Syn	Raw	Syn
2024	40.10	40.43	36.13	39.33	10.15	10.87	3.69	1.62	1.71	0.69
2025	33.70	33.89	30.49	32.53	8.44	9.05	6.25	3.52	2.02	0.95
2026	34.86	34.86	31.46	33.34	8.55	8.67	11.50	2.18	2.48	0.82
2027	35.48	35.56	31.76	33.85	9.31	9.10	11.24	0.73	2.54	0.61
2028	35.39	35.19	32.11	33.31	9.52	9.14	13.57	2.82	2.66	0.91
2029	35.53	35.74	32.34	33.68	9.93	9.98	10.33	3.78	2.28	1.11
2030	35.30	35.08	32.25	33.07	9.77	9.34	6.15	0.73	1.72	0.68
2031	35.42	35.59	32.46	33.92	10.05	10.49	6.15	3.36	1.53	0.84
2032	35.31	35.42	32.94	33.76	9.43	9.28	4.19	1.02	1.34	0.57
2033	36.04	35.83	33.69	34.29	9.65	9.59	2.87	0.90	1.09	0.47
2034	36.92	36.91	34.45	35.27	10.08	9.77	3.89	1.12	1.14	0.64
2035	37.91	37.96	35.47	36.41	10.64	10.77	3.90	1.92	0.88	0.60

	Mean		Median		Standard deviation		Kurtosis		Skewness	
	Raw	Syn	Raw	Syn	Raw	Syn	Raw	Syn	Raw	Syn
2036	39.20	39.35	37.61	38.05	11.95	11.25	3.26	0.78	0.21	0.21
2037	40.62	40.27	40.13	39.73	14.28	13.41	2.20	0.28	-0.38	0.06
2038	42.46	42.21	42.53	41.94	15.70	15.91	1.60	0.13	-0.59	0.03
2039	44.07	43.88	45.29	44.57	18.33	18.67	0.90	-0.27	-0.70	-0.08
2040	45.41	45.44	47.38	45.69	21.31	20.22	0.32	-0.31	-0.68	0.01
2041	44.55	45.61	49.59	45.45	25.03	24.05	-0.45	-0.60	-0.57	0.14
2042	43.91	44.71	50.73	44.09	29.59	27.89	-0.96	-0.53	-0.31	0.28

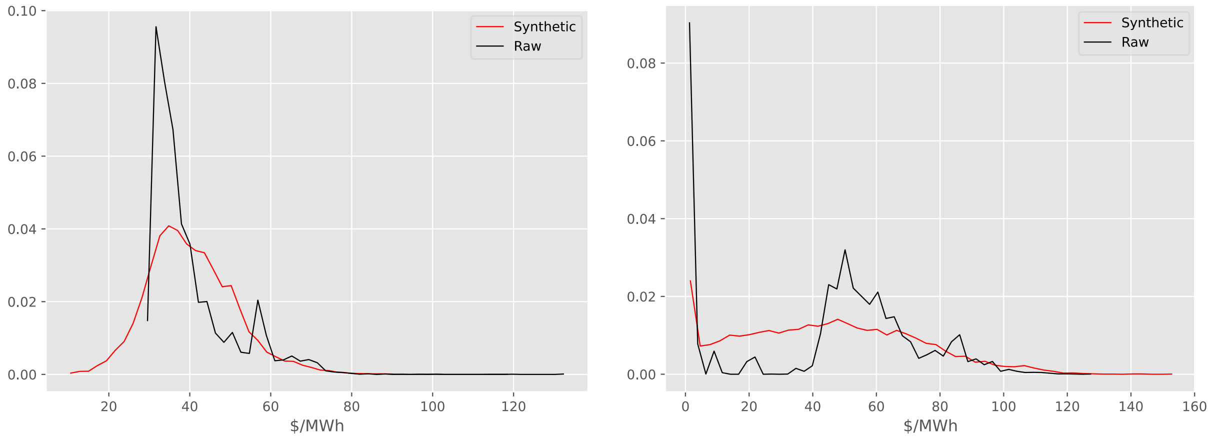


Figure 42. Probability density distributions of the raw and synthetic data in 2024 (left) and 2042 (right).

6. HEAT DEMAND AND CASE STUDY ANALYSIS

6.1 Steam-Extraction Methodology

The cost of extracting steam from the NPPs to provide industrial users with always-available clean steam was evaluated. Capital-cost estimating of the assumed steam-transport infrastructure between an existing NPP and an industrial plant started with a preconceptual design basis and cost-estimate analysis based on a design report by S&L [9] which evaluated low-pressure steam extraction for hydrogen production from a 4-loop Westinghouse PWR with a thermal power rating of 3650 MWt and a generating capacity of 1,225 MWe. Although that report considered low-pressure-extraction steam from the cross-under (cold-reheat) piping between the high-pressure turbine and the moisture-separator reheaters, it was subsequently scaled as part of this Gulf Coast study to approximate the piping and component costs associated with steam extraction from the main steam before the high-pressure turbine. This was required to provide the highest-pressure and temperature steam that an NPP can reasonably produce without significant modification to add superheat. This also assured the smallest heat-transport losses over reasonable distances while maximizing end-use pressure and temperature to an industrial user. The extraction scheme is shown in Figure 43.

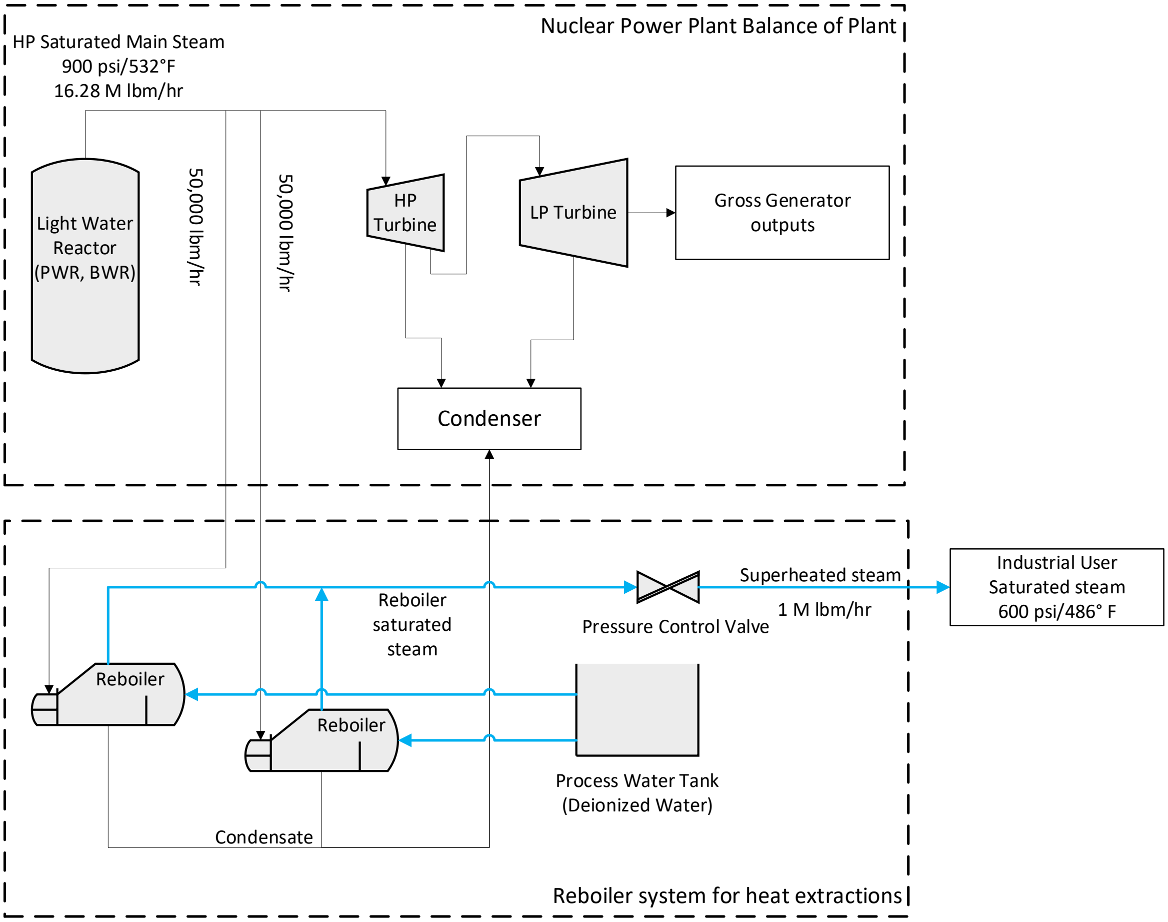


Figure 43. 15% thermal extraction PFD.

A steam-delivery system was designed based on an industrial-user requirement of 1 M lb/hr of 600 psi saturated steam. To deliver steam in these conditions, steam is extracted from the main steam system before the high-pressure turbine. An extraction case of 15% (~550 MWt) thermal extraction was evaluated. After extraction, the steam passes through a reboiler, where it boils demineralized feed water that is sent out of the plant boundary to industry. As a baseline, 15% extraction would require two reboiler trains. A second reboiler loop was assumed for this design. Additionally, a new control system would be required to ensure that changes in extracted steam would not increase reactivity within the NPP reactor.

To reduce the condensation in the line, the steam is slightly superheated on the front end through isothermal throttling to deliver 600-psi saturated steam to the industrial partner. The reboiler outlet temperature must approach the temperature between the main steam inlet and reboiler outlet to the main steam saturated temperature to provide enough superheat when dropping pressure across the throttle valve. A pipe size of 18-in. NPS was selected based on the design criteria below for two miles of pipe, at 600 psi saturated steam at 1 M lbm/hr:

- Reboiler outlet temperature held at the steam inlet temperature (~10°F target) to maximize superheat
- Optimal pipe size based on pressure drop within superheat conditions for a target of 600-psi saturated steam
- Pressure drop to 600 psi (200 psid)
- Steam velocity of 35 m/sec.

The cost to deliver steam was estimated by the cost of piping from the NPP to the industrial user and the additional installation of two reboilers. The cost per mile for additional piping is summarized in Table 14. The cost estimates for piping and reboiler costs were taken from the S&L report for the 500 MW_{nom} case [9]. Each reboiler costs approximately $1M. These costs include materials, labor, and equipment; contingency is not included.

Thermal energy delivery cost was estimated by the cost of piping from the NPP to the industrial user and the additional installation of two reboilers as shown in Table 14.

Table 14. Thermal transport piping costs (2022 U.S. dollars).

Piping from Reboilers to Industrial User	Cost ($/mile)
18-in. NPS piping	$2.84M
Insulation (3-in.-thick wool with aluminum jacketing)	$1.76M
Pipe supports/hangers	$671,074
TOTAL	$5.27M per mile

6.2 Thermal-Power Extraction from NPPs for Industrial Processes

A case study was conducted to identify potential industry partners near Waterford 3 that require clean steam. Three plants, shown in Table 15, are located within a 2-mile radius.

Table 15. Industry within 2 miles of Waterford 3.

Company	Industry	Distance from Waterford 3 (miles)
Dow St. Charles	Refinery	2
Am Agrigen	Ammonia	2
Occidental Chemical Corporation	Chemical	2

Steam costs for NPP steam and a base case of a natural gas reboiler were compared. The cost of heat delivery for the 500-MWe case is $13.0/MWhth for main-steam extraction before the high-pressure turbine [9]. This estimate assumes a constant electricity sales price at $30/MWh (in 2022 USD). Industrial boiler systems that use natural gas typically provide steam. As a base case, a natural gas-fed boiler was used. Steam cost was estimated using the correlation to natural gas price shown in Equation (5) [46].

$$Steam\ cost = \frac{fuel\ cost * (H_{steam} - H_{feedwater})}{1000 * boiler\ efficiency} \tag{5}$$

The following assumptions were made: 600-psi saturated steam, boiler efficiency of 80% [i], and fuel cost of $4/MMBTU. Based on these assumptions, the base case steam cost is $5.10/1000 lbm steam or $13.64/MWth.

Waterford 3 is located near abundant chemical and refining industries that could benefit from a source of always available clean steam. Three major opportunities within a 2-mile radius were identified for thermal heat integration. The cost for additional piping and equipment to transport steam within 2 miles, based on an assumed delivery rate of 1 M lbm/hr at 600-psi saturated steam, is $12.5M.

At a natural gas price of \$4.59/MMBTU the cost of nuclear steam and a typical natural gas-fed boiler break even. As ESG pressures continue to rise for large industrial facilities, the demand for an always available source of clean heat increases. As ESG pressures continue to rise for large industrial facilities, the demand for a source of clean heat available 24/7 increases. Further investigation on the application of PTC for clean steam is necessary to evaluate the impact on financial feasibility of thermal energy transport.

6.3 Safety and Regulatory Considerations

Safety of the production of hydrogen considers two major hazards: fire and deflagration or detonation. A leaking pipe or tank with an ignition source will cause a plume fire or deflagration, with a burst of overpressure followed by a fire, or a more-powerful detonation. The detonation is analyzed instead of the deflagration because it is the bounding overpressure event. Figure 44, taken from the HyRAM+ (hydrogen hazards analysis software from Sandia National Laboratories) analysis of a jet-leak detonation of hydrogen, shows the regions susceptible to the different types of hazards. The red region shows where a fire is possible, the blue region shows where a detonation is possible. The masses available for each type of hazard is calculated in HyRAM+ based on the pressure and volume of the pipe and the size of the pipe leak.

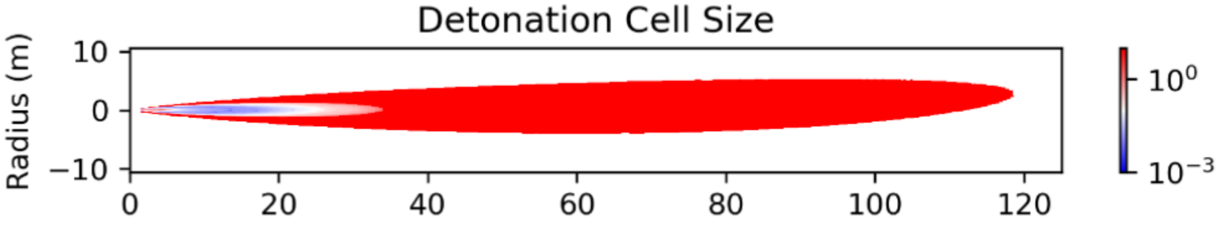


Figure 44. Hydrogen jet leak plume showing detonation region in blue.

Safety and regulatory licensing considerations are affected by the existing NPP site. Each NPP has its own fire protection plan within the owner-controlled area that has been agreed to with the U.S. NRC. The fire protection plan dictates the safe standoff distance required of a hydrogen facility for fires and the resultant heat flux. This is typically determined from National Fire Protection Association (NFPA) Standard 55; however, other standards may apply, depending on the fire protection plan of the specific NPP site.

Detonation-overpressure safe distancing is dictated by the point at which a potential hydrogen-detonation overpressure wave will dissipate to 1.0 psi force. NFPA standards seek to determine a reasonable leak percentage from a hydrogen facility pipe, and NFPA 55 has a standoff distance based on that versus the stored hydrogen in the facility. NRC's Regulation Guide (RG) 1.91 for nearby explosive sources to an NPP uses a more-conservative approach in its wording and requires the 1.0 psi overpressure limit based on a TNT-equivalence calculation. NRC RG 1.91 is designed to be applied for explosive hazards outside of the owner-controlled area, but the 1.0-psi limit is a pressure that is acceptable for any system, structure, or component. Recent INL research used a full-break leak of a generically designed 500 MW HTEF to determine safe standoff distances. This safe distance is more conservative than the NFPA 55; still, at 233-m standoff distance to the nearest system, structure, or component, the HTEF will fit within the owner-controlled area of the TEA NPPs, and most existing NPPs in the U.S. It is our recommendation to use this methodology to site the hydrogen facility because it will also satisfy fire protection plan requirements. However, should space availability be a hindrance, the NFPA standards, or using a Bauwens-Durofeev methodology specific to hydrogen detonations—instead of a TNT equivalent mass equation—can be less conservative and would provide acceptable safe separation distances to the NRC.

7. CONCLUSION

The report underscores the U.S. nuclear-generation fleet's vital role in achieving climate goals, emphasizing its reliance on LWR technologies. This fleet is the largest provider of U.S. carbon-free electrical generation, ensuring consistent, always-available clean-energy stability. With a track record of reliability and capacity factors consistently above 90%, the existing nuclear fleet is a cornerstone for sustainable energy.

The Gulf Coast region, with its extensive hydrogen pipeline infrastructure, supports integrating LWRs with hydrogen production, facilitating efficient hydrogen transport from production sites to end-users. Strategic locations of reactors near major industrial centers ensure efficient hydrogen delivery, reducing transportation costs and supporting decarbonization efforts. Additionally, the region's potential hydrogen-storage capabilities, including compressed gas and underground storage in salt caverns, ensure a continuous and reliable hydrogen supply.

The market analysis anticipates substantial existing and potential hydrogen demand from various sectors. Key findings highlight the highest hydrogen demand surrounding Waterford, Riverbend, and South Texas NPPs, with ammonia and refineries being predominant consumers. This underscores the role of nuclear-generated hydrogen in supporting crucial industries.

7.1 Techno-Economic Assessment Findings

The findings of this TEA include:

- **Scenarios Evaluated**
  - **Case 1A**: HTSE to hydrogen pipeline network, producing 351 tonnes/day
  - **Case 1B**: HTSE directly supplied to an industrial user, producing 351 tonnes/day
  - **Case 2A**: LTE to hydrogen pipeline network, producing 231 tonnes/day
  - **Case 2B**: LTE directly supplied to an industrial user, producing 231 tonnes/day
- **Potential Industrial Customers**: Identified nearby plants could benefit from clean hydrogen or steam supply
- **Tax Credit Opportunities**
  - **IRA Section 45U**: Provides up to $15 per MWh for zero-emission nuclear power production if electricity price is below $25/MWh
  - **IRA Section 45V**: Offers a maximum tax credit of $3 per kg of clean hydrogen produced if associated GHG emissions are below 4.0 kg CO_2/kg-H_2
- **Hydrogen Delivery Costs**: Minimal impact on overall costs, with maximum delivery costs no more than $0.5/kg-$H_2$ at Comanche Peak due to its longer transportation distances and lower demand
- **LCOH**
  - HTSE scenarios (Case 1A and 1B) have lower LCOHs than LTE scenarios (Case 2A and 2B) due to higher hydrogen production rates
  - LCOHs for Case 1B and Case 2B are slightly higher for Grand Gulf and Comanche Peak due to reduced hydrogen demand
  - After-tax cases with tax credits reduce LCOH by about $1.8/kg-$H_2$, making nuclear-integrated hydrogen production more competitive
  - HTSE cases, including tax credits, can result in a negative cost of hydrogen for Comanche Peak, allowing it to compete with blue hydrogen

- **Delta NPV of cashflows**
  - Negative before tax credits, indicating hydrogen production is less profitable than selling electricity to the grid at equal electricity costs
  - Positive for HTSE after tax credits, making it the preferred method.

The study also addresses the feasibility of transporting steam to nearby industrial facilities, with Waterford Nuclear Generating Station as a case study. The capital cost estimate for steam transport infrastructure was based on preconceptual design and cost analysis, meeting the requirements for the Gulf Coast study.

7.2 Thermal Delivery Key Findings

This study found the following on the subject of demand for industrial heat:

- **Steam Transport Infrastructure Cost** estimated at $12.5 million
- **Comparative Cost of Heat Delivery**
  - Nuclear steam extraction: $13.0/MWhth
  - Natural gas-fed boiler: $13.64/MWth, breaking even at a natural gas price of $4.59/MMBTU.

The findings of this study provide a strategic foundation for leveraging NPPs in the clean-energy sector, particularly for hydrogen production. By integrating nuclear power with hydrogen production and exploring industrial heat opportunities, the U.S. can make significant strides in decarbonizing key industries and achieving its climate goals.

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[47]

Appendix A

Detailed Tables of Future Potential Hydrogen Demand (MT/day) from Various Facilities Within a 100 Miles of Each of the NPPs Included

Table A-1. Riverbend NPP.

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
St Francisville Mill: Hood Container of Louisiana, LLC	Natural gas electricity generators (NGEGs)	5	7
Big Cajun 2: Louisiana Generating LLC	NGEGs	16	9
Big Cajun 1: Louisiana Generating LLC	NGEGs	3	12
Georgia-Pacific Port Hudson: Georgia-Pacific Cons Op LLC Port Hudson	NGEGs	7	13
ExxonMobil Corporation, Baton Rouge	Refinery	535	25
ExxonMobil Baton Rouge Turbine Generator: ExxonMobil Corporation	NGEGs	15	26
Louisiana 1: Entergy Louisiana LLC	NGEGs	41	26
Formosa Plastics: Formosa Plastics Corporation	NGEGs	8	26
Placid Oil Co, Port Allen	Refinery	80	29
Port Allen (LA): Placid Refining Co LLC	NGEGs	1	29
LSU Cogen: LSU and Agriculture and Military (A&M) College	NGEGs	2	31
Plaquemine Cogeneration Plant: Dow Chemical Co	NGEGs	92	41
LaO Energy Systems: Dow Chemical Co	NGEGs	18	41
Alon Israel Oil Company Ltd, Krotz Springs	Refinery	85	41
Axiall Plaquemine: Axiall Corporation	NGEGs	38	47
EuroChem, Edgard	Ammonia	430	51
Nutrien, Geismar	Ammonia	260	53
Carville Energy LLC: Carville Energy LLC	NGEGs	52	53
Geismar Cogen: Air Liquide Large Industries U.S. LP	NGEGs	12	53
Shell Chemicals: Air Liquide America Corporation	NGEGs	17	54
Geismar: BASF Corporation	NGEGs	15	54
Burnside Alumina Plant: Almatis Burnside Inc.	NGEGs	6	58
Motiva Enterprises LLC, Convent	Refinery	242	60

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
Cf Industries, Donaldsonville	Ammonia	1868	66
Louisiana Sugar Refining: Louisiana Sugar Refining LLC	NGEGs	4	72
Gramercy Holdings LLC	NGEGs	24	72
Marathon Petroleum Corporation, Garyville	Refinery	578	76
T J Labbe Electric Generating: Lafayette Utilities System	NGEGs	0.46	83
Acadia Energy Center: Cleco Power LLC	NGEGs	72	84
Bayou Steel Group	DRI	4	85
Coughlin Power Station: Cleco Power LLC	NGEGs	37	88
Hargis-Hebert Electric Generating: Lafayette Utilities System	NGEGs	1	89
AM Agrigen, Killona	Ammonia	216	89
Little Gypsy: Entergy Louisiana LLC	NGEGs	50	89
Motiva Enterprises LLC, Norco	Refinery	240	90
Waterford 1 and 2: Entergy Louisiana LLC	NGEGs	19	91
Valero St. Charles Refinery	Refinery	229	91
Taft Cogeneration Facility: Occidental Chemical Corporation	NGEGs	83	92
LEPA Unit No. 1: Louisiana Energy and Power Authority	NGEGs	4	93
Dow St Charles Operations: Dow Chemical Company—St Charles	NGEGs	50	94
D G Hunter: City of Alexandria, LA	NGEGs	3	100
Royal Dutch Shell Group, St. Rose, LA	Refinery	48	100

Table A-2. Grand Gulf NPP.

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
Baxter Wilson: Entergy Mississippi Inc	NGEGs	14	22
Ergon Biofuels LLC, Vicksburg	Syngas: Ethanol	55	31
Ergon Refining Vicksburg: Ergon Refining Inc	NGEGs	1	31
Ergon Inc, Vicksburg	Refinery	28	32
International Paper Vicksburg Mill: International Paper Co-Vicksbg	NGEGs	4	42
Rex Brown: Entergy Mississippi Inc	NGEGs	4	67
Hinds Energy Facility: Entergy Mississippi Inc	NGEGs	45	68

Mississippi Baptist Medical Center: Mississippi Baptist Medical	NGEGs	0.139	73
Nucor Steel—Jackson Inc.	DRI	4	74
Yazoo: Public Serv Comm of Yazoo City	NGEGs	0.005	74
Cf Industries, Yazoo City	Ammonia	249	79
CF Industries Yazoo City Complex: CF Industries Nitrogen LLC	NGEGs	4	79
Georgia-Pacific Monticello Paper: Georgia-Pacific Monticello LLC	NGEGs	4	94

Table A-3. Waterford NPP.

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
Waterford 1and 2: Entergy Louisiana LLC	NGEGs	19	1
Taft Cogeneration Facility: Occidental Chemical Corporation	NGEGs	83	1
Dow St Charles Operations: Dow Chemical Co - St Charles	NGEGs	50	2
Am Agrigen, Killona	Ammonia	216	2
Royal Dutch/Shell Group, Saint Rose	Refinery	48	15
Dyno Nobel, Waggaman	Ammonia	400	16
Motiva Enterprises LLC, Norco	Refinery	240	17
Valero Energy Corporation, Norco	Refinery	229	18
Gramercy Holdings LLC: Gramercy Holdings LLC	NGEGs	24	22
Louisiana Sugar Refining: Louisiana Sugar Refining LLC	NGEGs	4	23
Bayou Steel Group	DRI	4	26
Little Gypsy: Entergy Louisiana LLC	NGEGs	50	27
Nine-mile Point: Entergy Louisiana LLC	NGEGs	157	27
Marathon Petroleum Corporation, Garyville	Refinery	578	28
Domino Sugar Arabi Plant: American Sugar Refining Inc.	NGEGs	4	38
Cf Industries, Donaldsonville	Ammonia	1868	39
Motiva Enterprises LLC, Convent	Refinery	242	39
Pbf Energy Co LLC, Chalmette	Refinery	202	39
Burnside Alumina Plant: Almatis Burnside Inc.	NGEGs	6	39
Houma: Terrebonne Parish Consol Gov’t	NGEGs	1	41
Valero Energy Corporation, Meraux	Refinery	133	41
Geismar Cogen: Air Liquide Large Industries U.S. LP	NGEGs	12	43

Name	Demand Type	Future Potential Demand, MT/day	Distance (mi)
Shell Chemical: Air Liquide America Corporation	NGEGs	17	44
Geismar: BASF Corporation	NGEGs	15	44
Oak Point Cogen: Chevron Oronite Co LLC	NGEGs	4	46
Nutrien, Geismar	Ammonia	260	48
Carville Energy LLC	NGEGs	52	49
Phillips 66 Company, Belle Chasse	Refinery	263	56
Alliance Refinery: Phillips 66	NGEGs	0.17	56
Axiall Plaquemine: Axiall Corporation	NGEGs	38	57
Eurochem, Edgard	Ammonia	430	58
LaO Energy Systems: Dow Chemical Co	NGEGs	18	62
Plaquemine Cogeneration Plant: Dow Chemical Co	NGEGs	92	62
LSU Cogen: LSU and A&M College	NGEGs	2	63
Exxon Mobil Corporation, Baton Rouge	Refinery	535	67
Port Allen (LA): Placid Refining Co LLC	NGEGs	1	67
Placid Oil Co, Port Allen	Refinery	80	67
LEPA Unit No. 1: Louisiana Energy & Power Authority	NGEGs	4	67
Louisiana 1: Entergy Louisiana LLC	NGEGs	41	69
ExxonMobil Baton Rouge Turbine Generator: Exxon Mobil Corporation	NGEGs	15	69
Formosa Plastics: Formosa Plastics Corporation	NGEGs	8	69
Georgia-Pacific Port Hudson: Georgia-Pacific Cons Op LLC Port Hudson	NGEGs	7	82
Gaylord Container Bogalusa: Temple-Inland Corporation	NGEGs	2	88
Big Cajun 1: Louisiana Generating LLC	NGEGs	3	88
Grand Isle Gas Plant	NGEGs	0	92
Big Cajun 2: Louisiana Generating LLC	NGEGs	16	93
Teche: Cleco Power LLC	NGEGs	17	94
Buras: Entergy Louisiana LLC	NGEGs	0.17	94
St Francisville Mill: Hood Container of Louisiana, LLC	NGEGs	5	98

Table A-4. Avoided cost of carbon estimation.

ACC (\$/MT CO_2)					
Case	Waterford 3	Riverbend	Grand Gulf	South Texas	Comanche Peak
1A	\$247.1	\$247.1	\$247.1	\$303.0	\$303.0
2A	\$377.8	\$377.8	\$377.8	\$459.8	\$459.8
1B	\$247.1	\$247.1	\$356.4	\$303.0	\$324.4
2B	\$377.8	\$377.8	\$463.4	\$459.8	\$478.8

Table A-5. Avoided net cost of carbon estimations.

ANCC (\$/MT CO_2)					
Case	Waterford 3	Riverbend	Grand Gulf	South Texas	Comanche Peak
1A	\$29.7	\$29.7	\$33.3	\$85.5	\$95.1
2A	\$167.5	\$167.5	\$171.1	\$248.3	\$261.4
1B	\$29.7	\$29.7	\$148.5	\$85.5	\$114.1
2B	\$167.5	\$167.5	\$262.6	\$248.3	\$275.6

Appendix B

Detailed Tables of Financial Performance for Nuclear-Integrated Hydrogen Production through HTSE (Case 1A and Case 1B) and LTE (Case 2A and Case 2B)

B.1. CASE 1A: NUCLEAR-INTEGRATED HYDROGEN PRODUCTION THROUGH HTSE CONNECTED TO NEARBY PIPELINES

Table B-1. Financial performance for Waterford, Riverbend, Grand Gulf, STP, and CP with various electricity price before taxes.

	H_2 Production only					
Cases	**Waterford**	**Riverbend**		**Grand Gulf**	**STP**	**CP**
Electricity price	$35/MWh	$35/MWh	$35/MWh	$31/MWh	$20/MWh	
LCOH ($2022)	$2.08	$2.08		$2.08	$1.92	$1.49
LCOH+COD ($2022)	$0.09	$0.10		$0.19	$0.10	$0.37
IRR_{H2}	11%	11%		16%	11%	25%
NPV_{H2} of cashflows	$122 M	$135 M		$257 M	$134 M	$499 M
Daily H_2 Production	351 tpd	351 tpd		351 tpd	351 tpd	351 tpd
	Electricity Production Only: BAU					
NPV_{BAU} of cashflows	$1,809 M	$1,809 M		$1,809 M	$1,593 M	$1,032 M
$\Delta NPV=NPV_{H2}- NPV_{BAU}$	-$1,687 M	-$1,674 M		-$1,552 M	-$1,459 M	-$532 M

Table B-2. Financial performance for Waterford, Riverbend, Grand Gulf, STP, and CP with various electricity price after taxes.

	H_2 Production only				
Cases	**Waterford**	**Riverbend**	**Grand Gulf**	**STP**	**CP**
Electricity price ($2022)	$35/MWh	$35/MWh	$35/MWh	$31/MWh	$20/MWh
LCOH ($2022)	$0.25	$0.25	$0.28	$0.09	-$0.27
LCOH+COD ($2022)	$0.34	$0.35	$0.47	$0.19	$0.10
IRR_{H2}	141%	141%	144%	142%	152%
NPV_{H2} of cashflows	$2,595 M	$2,605 M	$2,693 M	$2,606 M	$2,874 M
Daily H_2 Production	351 tpd	351 tpd	351 tpd	351 tpd	351 tpd
	Electricity Production Only: BAU				
NPV_{BAU} of cashflows	$1,377 M	$1,377 M	$1,377 M	$1,300 M	$924 M
$\Delta NPV=NPV_{H2}- NPV_{BAU}$	$1,219 M	$1,228 M	$1,316 M	$1,306 M	$1,950 M

B.2. CASE 1B: NUCLEAR INTEGRATED HYDROGEN PRODUCTION THROUGH HTSE CONNECTED TO INDUSTRIAL USERS

Table B-3. Financial performance for Waterford, Riverbend, Grand Gulf, STP, and CP with various electricity price before taxes.

	H_2 Production only				
Cases	**Waterford**	**Riverbend**	**Grand Gulf**	**STP**	**CP**
Electricity price	$35/MWh	$35/MWh	$35/MWh	$31/MWh	$20/MWh
LCOH ($2022)	$2.08	$2.08	$3.00	$1.92	$1.67
LCOH+COD ($2022)	$2.18	$2.18	$3.24	$2.01	$1.96
IRR_{H2}	11%	11%	11%	11%	18%
NPV_{H2} of cashflows	$135 M	$135 M	$26 M	$121 M	$123 M
Daily H_2 Production	351 tpd	351 tpd	28 tpd	351 tpd	110 tpd
	Electricity Production Only: BAU				
NPV_{BAU} of cashflows	$1,809 M	$1,809 M	$145 M	$1,593 M	$323 M
$\Delta NPV=NPV_{H2}- NPV_{BAU}$	-$1,674 M	-$1,674 M	-$119 M	-$1,472 M	-$201 M

Table B-4. Financial performance for Waterford, Riverbend, Grand Gulf, STP, and CP with various electricity price after taxes.

	H_2 Production only				
Cases	**Waterford**	**Riverbend**	**Grand Gulf**	**STP**	**CP**
Electricity price ($2022)	$35/MWh	$35/MWh	$35/MWh	$31/MWh	$20/MWh
LCOH ($2022)	$0.25	$0.25	$1.25	$0.08	-$0.11
LCOH+COD ($2022)	$0.35	$0.35	$1.49	$0.17	$0.18
IRR_{H2}	141%	141%	58%	141%	114%
NPV_{H2} of cashflows	$2,595 M	$2,605 M	$2,693 M	$2,606 M	$2,874 M
Daily H_2 Production	351 tpd	351 tpd	351 tpd	351 tpd	351 tpd
	Electricity Production Only: BAU				
NPV_{BAU} of cashflows	$1,377 M	$1,377 M	$111 M	$1,300 M	$290 M
$\Delta NPV=NPV_{H2}- NPV_{BAU}$	$1,228 M	$1,228 M	$105 M	$1,296 M	$583 M

B.3. CASE 2A: NUCLEAR INTEGRATED HYDROGEN PRODUCTION THROUGH LTE CONNECTED TO NEARBY PIPELINES

Table B-5. Financial performance for Waterford, Riverbend, Grand Gulf, STP, and CP with various electricity price before taxes.

	H_2 Production only				
Cases	**Waterford**	**Riverbend**	**Grand Gulf**	**STP**	**CP**
Electricity price	$35/MWh	$35/MWh	$35/MWh	$31/MWh	$20/MWh
LCOH ($2022)	$3.18	$3.18	$3.18	$2.95	$2.31
LCOH+COD ($2022)	$3.27	$3.29	$3.40	$3.06	$2.79
IRR_{H2}	11%	12%	17%	12%	29%
NPV_{H2} of cashflows	$82 M	$100 M	$201 M	$100 M	$437 M
Daily H_2 Production	231 tpd	231 tpd	231 tpd	231 tpd	231 tpd
	Electricity Production Only: BAU				
NPV_{BAU} of cashflows	$1,851 M	$1,851 M	$1,851 M	$1,631 M	$1,056 M
$\Delta NPV=NPV_{H2}- NPV_{BAU}$	-$1,769 M	-$1,751 M	-$1,651 M	-$1,531 M	-$619 M

Table B-6. Financial performance for Waterford, Riverbend, Grand Gulf, STP, and CP with various electricity price after taxes.

	H_2 Production only				
Cases	Waterford	Riverbend	Grand Gulf	STP	CP
Electricity price ($2022)	$35/MWh	$35/MWh	$35/MWh	$31/MWh	$20/MWh
LCOH ($2022)	$1.41	$1.41	$1.44	$1.16	$0.63
LCOH+COD ($2022)	$1.50	$1.52	$1.66	$1.27	$1.11
IRR_{H2}	116%	117%	120%	118%	129%
NPV_{H2} of cashflows	$1,701 M	$1,714 M	$1,787 M	$1,720 M	$1,966 M
Daily H_2 Production	231 tpd	231 tpd	231 tpd	231 tpd	231 tpd
	Electricity Production Only: BAU				
NPV_{BAU} of cashflows	$1,409 M	$1,409 M	$1,409 M	$1,331 M	$946 M
$\Delta NPV=NPV_{H2}- NPV_{BAU}$	$292 M	$305 M	$378 M	$389 M	$1,019 M

B.4. CASE 2B: NUCLEAR INTEGRATED HYDROGEN PRODUCTION THROUGH LTE CONNECTED TO INDUSTRIAL USERS

Table B-7. Financial performance for Waterford, Riverbend, Grand Gulf, STP, and CP with various electricity price before taxes.

	H_2 Production only				
Cases	Waterford	Riverbend	Grand Gulf	STP	CP
Electricity price	$35/MWh	$35/MWh	$35/MWh	$31/MWh	$20/MWh
LCOH ($2022)	$3.18	$3.18	$3.90	$2.95	$2.47
LCOH+COD ($2022)	$3.28	$3.29	$4.14	$3.04	$2.76
IRR_{H2}	11%	12%	12%	11%	19%
NPV_{H2} of cashflows	$91 M	$100 M	$27 M	$82 M	$126 M
Daily H_2 Production	231 tpd	231 tpd	28 tpd	231 tpd	110 tpd
	Electricity Production Only: BAU				
NPV_{BAU} of cashflows	$1,851 M	$1,851 M	$226 M	$1,631 M	$503 M
$\Delta NPV = NPV_{H2} - NPV_{BAU}$	-$1,760 M	-$1,751 M	-$199 M	-$1,549 M	-$377 M

Table B-8. Financial performance for Waterford, Riverbend, Grand Gulf, STP, and CP with various electricity price after taxes.

	H_2 Production only				
Cases	Waterford	Riverbend	Grand Gulf	STP	CP
Electricity price ($2022)	$35/MWh	$35/MWh	$35/MWh	$31/MWh	$20/MWh
LCOH ($2022)	$1.41	$1.41	$2.21	$1.16	$0.75
LCOH+COD ($2022)	$1.51	$1.52	$2.45	$1.25	$1.04
IRR_{H2}	117%	117%	69%	118%	108%
NPV_{H2} of cashflows	$1,708 M	$1,714 M	$215 M	$1,706 M	$872 M
Daily H_2 Production	231 tpd	231 tpd	28 tpd	231 tpd	110 tpd
	Electricity Production Only: BAU				
NPV_{BAU} of cashflows	$1,409 M	$1,409 M	$172 M	$1,331 M	$451 M
$\Delta NPV = NPV_{H2} - NPV_{BAU}$	$299 M	$305 M	$43 M	$376 M	$421 M

Appendix C

Figures for Competitive Analysis

C.1. GRAND GULF NPP

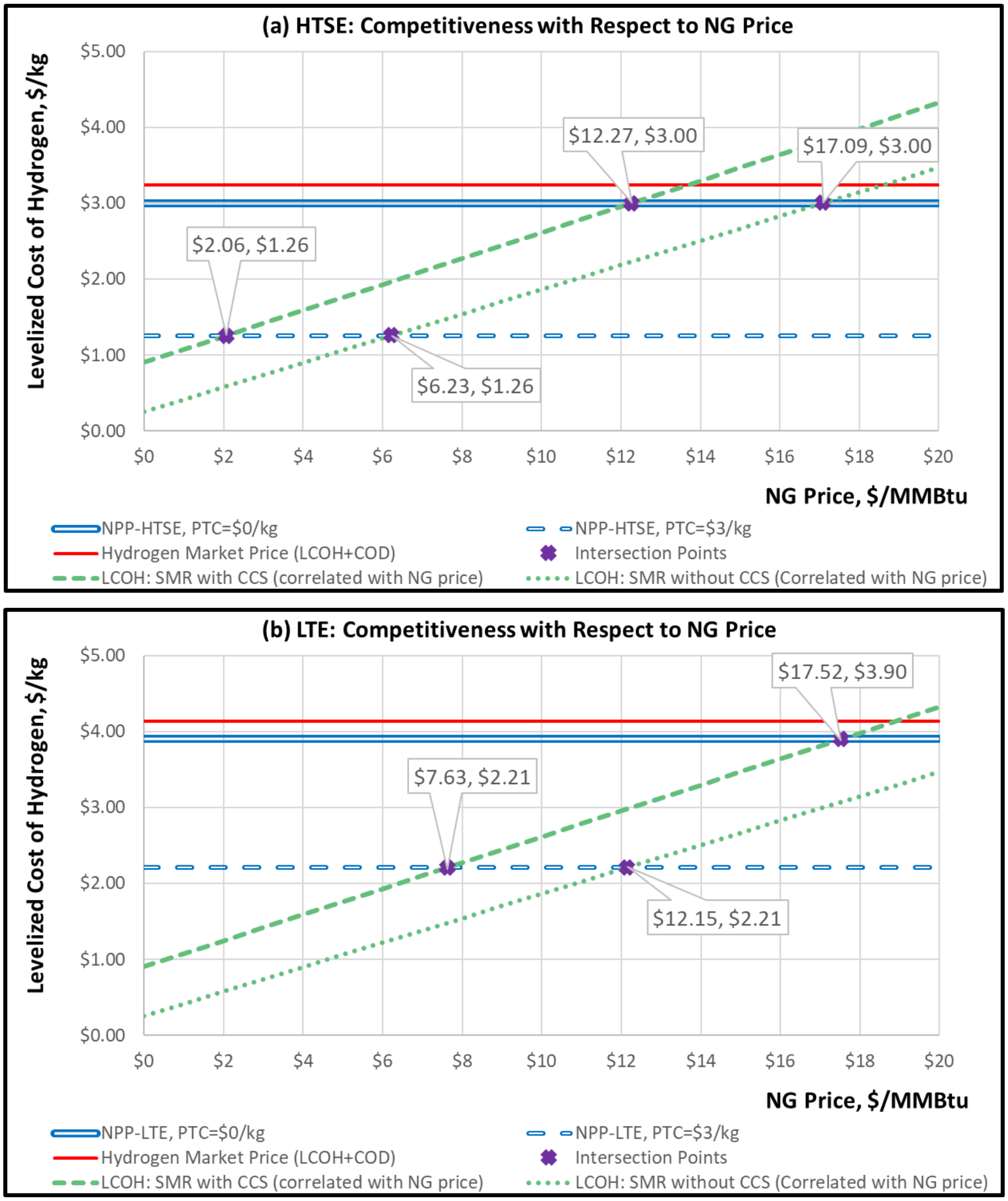
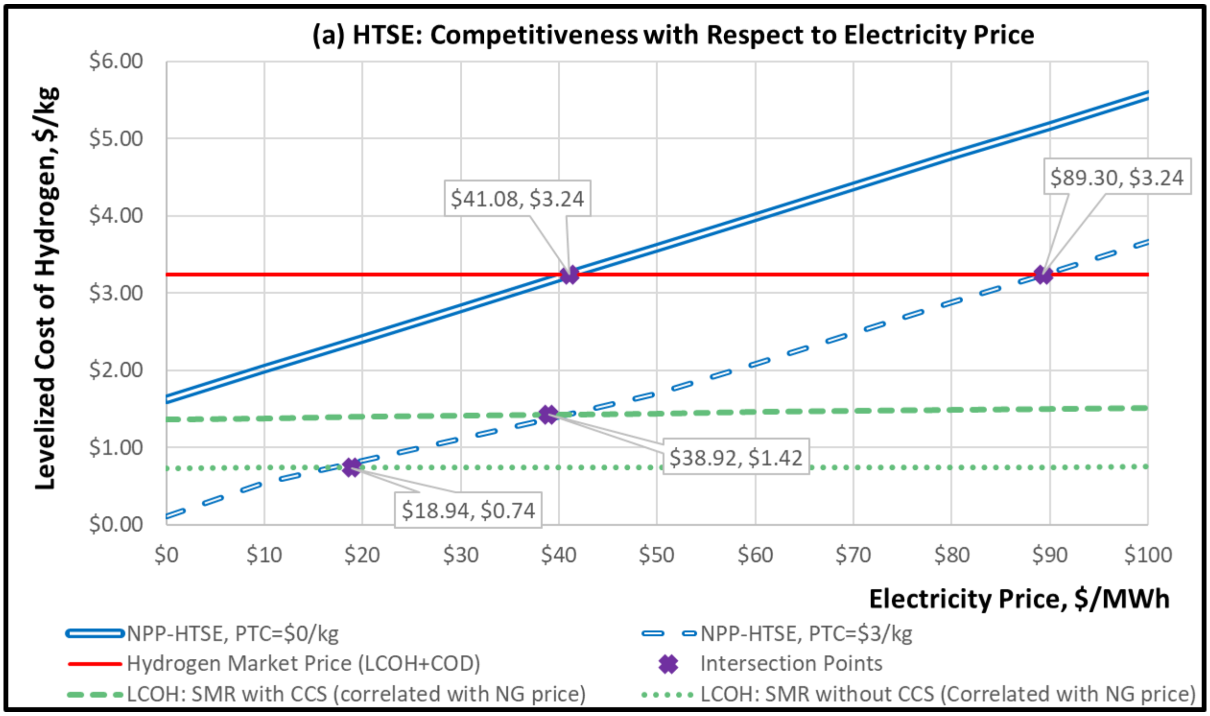


Figure C-1. Competitive analysis with respect to natural gas for hydrogen production for (a) Case 1B: a 40 MW-dc HTSE plant connected to the refinery plant and (b) Case 2B: a 61 MW-dc LTE plant connected to the refinery plant. Hydrogen is produced with 20 years of plant life, 5.66 % of WACC, user-defined electricity fixed price, and hydrogen market price equivalent to summation of LCOH and COD.



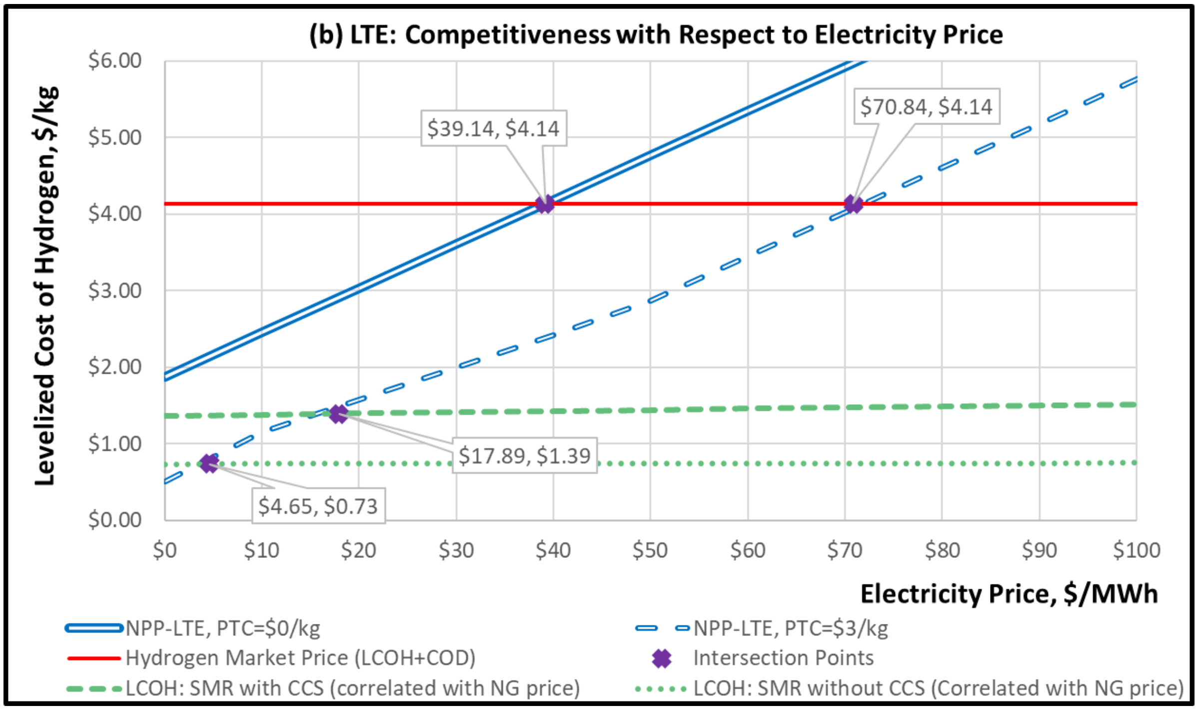
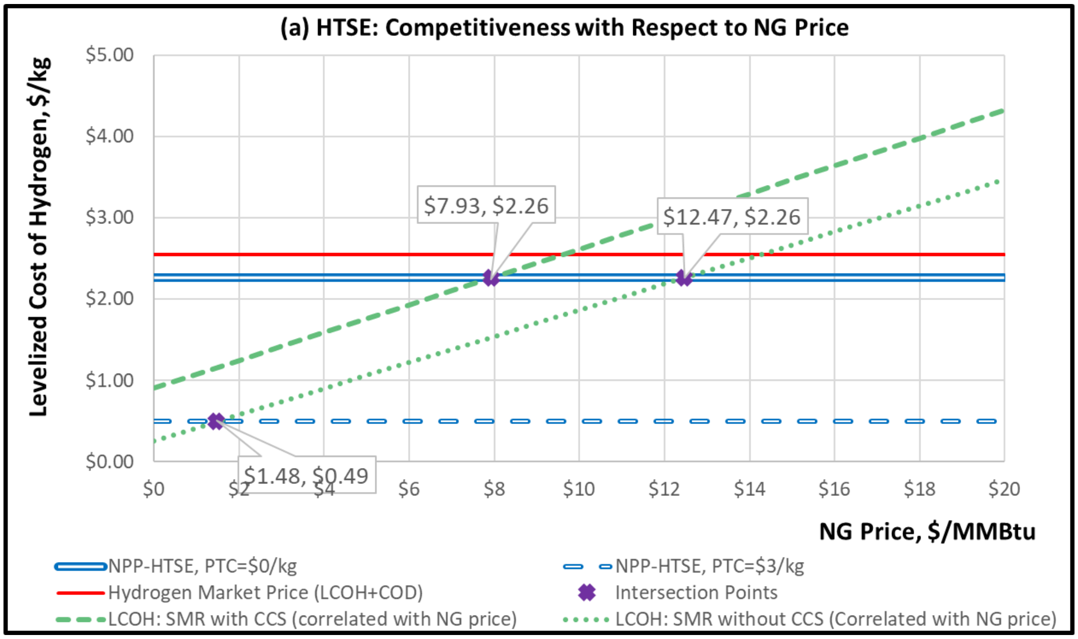


Figure C-2. Competitive analysis with respect to electricity costs for hydrogen production for (a) Case 1B: a 40 MW-dc HTSE plant connected to the refinery plant and (b) Case 2B: a 61 MW-dc LTE plant connected to the refinery plant. Hydrogen is produced with 20 years of plant life, 5.66 % of WACC, user-defined electricity fixed price, and hydrogen market price equivalent to summation of LCOH and COD.

C.2. CP NPP



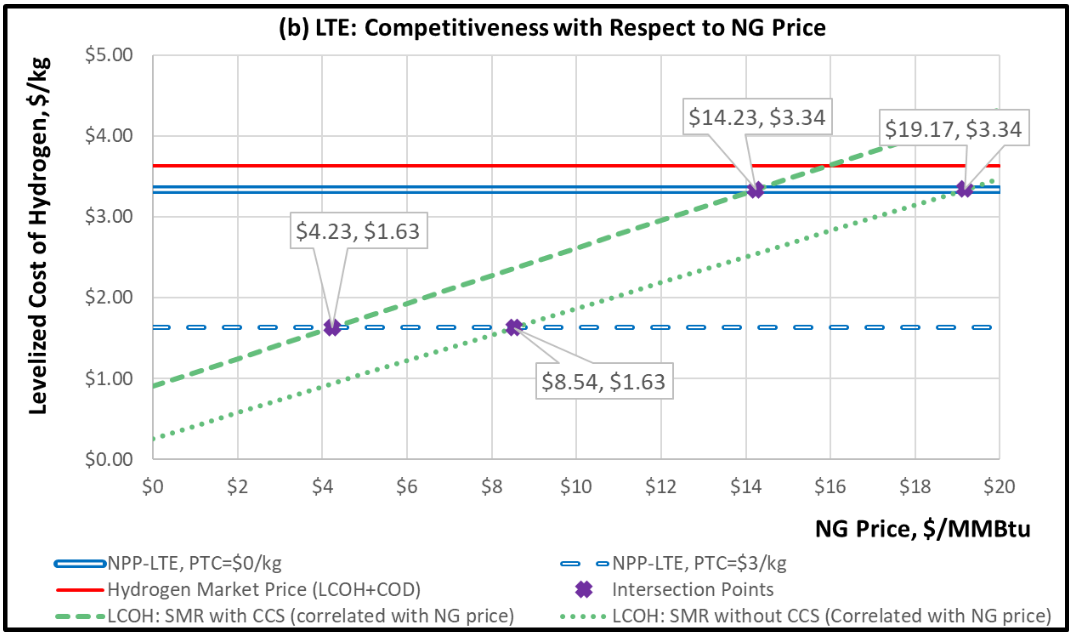


Figure C-3. Competitive analysis with respect to natural gas price for hydrogen production for (a) Case 1B: a 157 MW-dc HTSE plant connected to the E-fuel plant and (b) Case 2B: a 238 MW-dc LTE plant connected to the E-fuel plant. Hydrogen is produced with 20 years of plant life, 5.69 % of WACC, user-defined electricity fixed price, and hydrogen market price equivalent to summation of LCOH and COD.

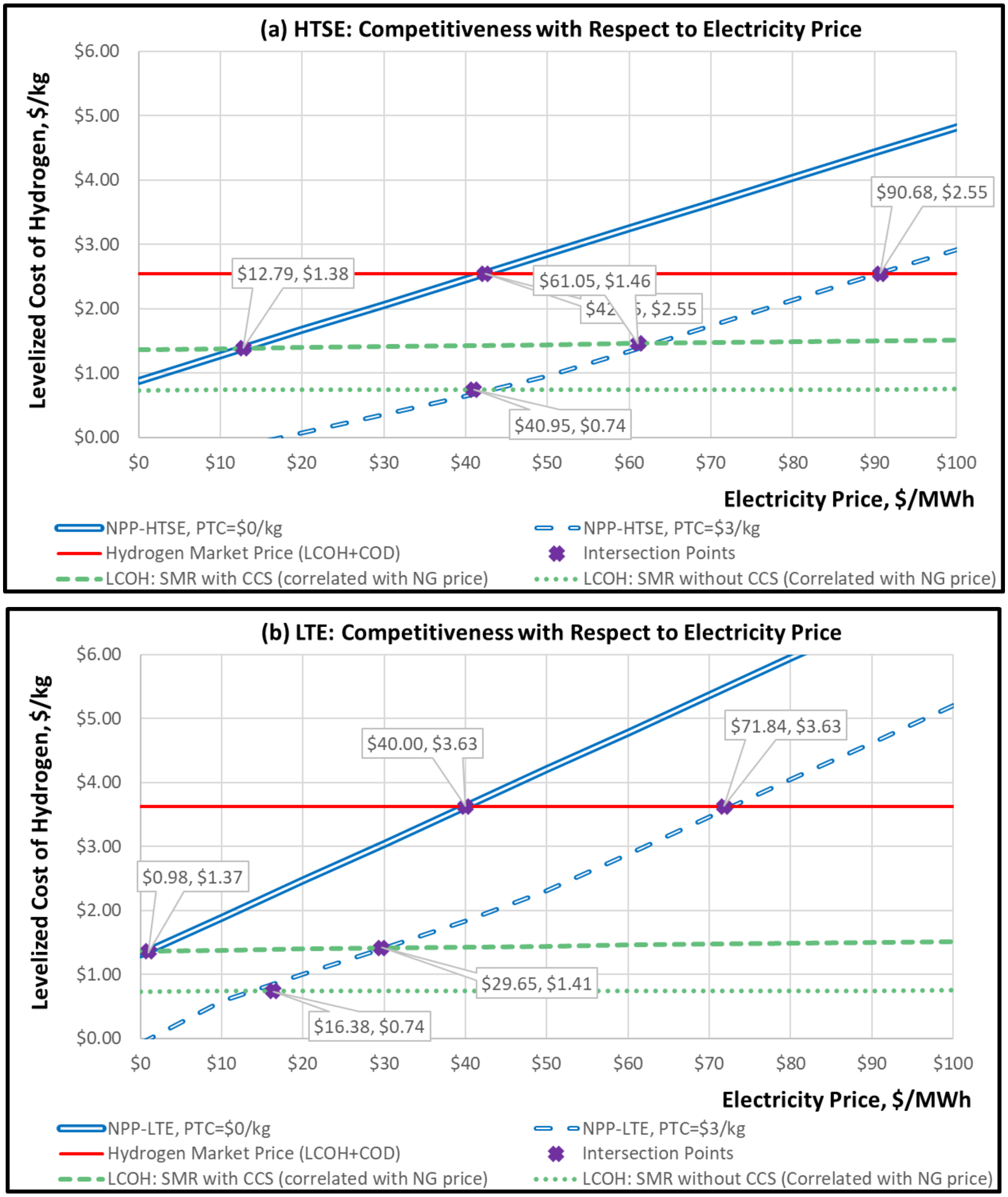


Figure C-4. Competitive analysis with respect to electricity costs for hydrogen production for (a) Case 1B: a 157 MW-dc HTSE plant connected to the E-fuel plant and (b) Case 2B: a 238 MW-dc LTE plant connected to the E-fuel plant. Hydrogen is produced with 20 years of plant life, 5.69 % of WACC, user-defined electricity fixed price, and hydrogen market price equivalent to summation of LCOH and COD.